EUROPEAN COMMISSION
Competition DG

Energy, Basic Industries, Chemicals and Pharmaceuticals
Energy, Water

ENERGY SECTOR INQUIRY

DRAFT PRELIMINARY REPORT

NON-CONFIDENTIAL VERSION

For reasons of confidentiality, company names have been excluded and figures in brackets indicate a range.

TABLE OF CONTENTS

EXECUTIVE SUMMARY

Introduction

Following further analysis of the data gathered in the Energy Sector Inquiry, the present Preliminary Report confirms the initial findings presented in the Issues Paper[1] (November 2005). The five main barriers to a fully functioning internal energy market are:

(1) Market concentration

(2) Vertical foreclosure

(3) Lack of market integration

(4) Lack of transparency

(5) Price formation

The Inquiry was launched in June 2005 and is a competition investigation based on Article 17 of Regulation 1/2003, which assesses the competition conditions on European gas and electricity markets and examines whether current indications of market malfunctioning result from breaches of competition law. The overall objective of the Inquiry is to address the barriers currently impeding the development of a fully functioning open and competitive EU-wide energy market by 1st July 2007.

The wider context has been set out in the Commission's Communication to the 2006 Spring European Council[2] concerning the renewed Growth and Jobs strategy. This puts the creation of an efficient and integrated energy policy at the heart of the Commission's priorities. This context will be further developed in the Green Paper on an integrated European Energy Policy that the Commission has announced will be submitted in early March.

The recent meeting of G8 Finance Ministers, in preparation for the G8 St Petersburg Summit, has further emphasized the goal of open energy markets in stating that market mechanisms are vital to the effective functioning of the global energy system.

Both the European consumer and European industry[3] are heavily dependent on the secure and reliable provision of energy at competitive and fair prices. Also, the achievement of the Union's goals for the environment are heavily linked to the reduction of greenhouse gases in the energy sector and the achievement of the Kyoto commitments.

The main findings of the Inquiry to date are summarised below for the gas and electricity markets.

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1 www.europa.eu.int/comm/competition/antitrust/others/sector_inquiries/energy/issues_paper15112005.pdf

2 Time to move up a gear - Annual Progress on Growth and Jobs, 25 January 2006

3 See Implementing the Community Lisbon Programme: a policy framework to strengthen EU manufacturing - towards a more integrated approach for industrial policy, Communication from the Commission, 5 October 2005. The Communication has led inter alia to the setting up of a High Level Group on Competitiveness, Energy and the Environment which will take up its work by the end of February 2006.

The Findings - Gas Markets:

Market concentration:

At the wholesale level, markets generally maintain the high level of concentration of the pre-liberalisation period. Wholesale trade has been slow to develop, and the incumbents remain dominant on their traditional markets, by largely controlling up-stream gas imports and/or gas production. Incumbents trade only a small proportion of their gas on hubs. With little new entry in retail markets, customer choice is limited and competitive pressure reduced. The overall picture for potential new entrants is one of dependency on vertically integrated incumbents for services throughout the supply chain.

Vertical foreclosure:

Lack of liquidity and limited access to infrastructure prevent new entrant suppliers from offering their services to the consumer. The network of long term supply contracts between gas producers and incumbent importers, makes it very difficult for new entrants to access gas on the upstream markets. Additionally, certain features of these contracts limit incentives for incumbents to provide liquidity on traded markets. Considering the highly concentrated upstream markets, it is particularly important to avoid that these structures propagate into market foreclosure downstream. Gas infrastructure (networks and storage) is to a large extent owned by the incumbent gas importers, and the insufficient separation of this infrastructure from supply functions results in insufficient market opening. Despite EU rules on third party access and legal/functional unbundling, new entrants often lack effective access to networks, the operators of which are alleged to favour their own affiliates.

Market integration:

Cross-border sales do not presently exert any significant competitive pressure. Incumbents rarely enter other national markets as competitors and available capacity on cross-border import pipelines is limited. New entrants are unable to secure transit capacity on key routes. The primary capacity on transit pipelines is controlled by incumbents based on legacy contracts that derogate from normal third party access rules. This is reinforced by ineffective congestion management mechanisms, which can make it hard to secure even small volumes of short-term, interruptible capacity on the secondary market. In most cases, new entrants have not even secured capacity when there have been expansions of transit pipeline capacity.

Transparency:

There is a lack of reliable and timely information on the markets - normally the lifeblood of healthy competition. Network users request more transparency on access to networks, transit capacity and storage, going beyond the current minimum requirements set by EU legislation. To ensure a level playing field, users require information to be made available on an equal footing. Confidentiality rules also undermine effective transparency when given too wide an interpretation.

Price formation:

More effective and transparent price formation is needed in order to deliver the full advantages of market opening to consumers. Gas import contracts use price indices that are

linked to oil products and recent price increases have, therefore, closely followed developments in oil markets. This results in wholesale prices that fail to react to changes in the supply and demand for gas. No clear trend towards more market based pricing mechanisms can be observed in long-term import contracts. Gas prices on existing gas hubs have also been rising recently, and ensuring liquidity is crucial to improving confidence in price formation on gas hubs. Even when different producers are selling from the same field, the contracts generally contain the same price index and often even the same actual price.

The Findings - Electricity Markets:

Market concentration:

Most wholesale markets remain national in scope with high levels of concentration in generation, which gives scope for exercising market power. Sales on spot markets generally reflect the level of concentration in generation, unlike those for trading in forward markets which show less concentration. However, caution is needed in assessing market power in electricity markets only on the basis of market shares. Analysis of trading in power exchanges shows that, in a number of them, generators have the scope to raise prices, a concern also expressed in the inquiry by many customers. Analysis of generation portfolios also shows that the main generators have the ability to withdraw capacities to raise prices. Further assessment will be needed in order to determine whether operators have unduly used these possibilities to raise prices.

Vertical foreclosure:

Vertical integration of generation, supply and network activities has remained a dominant feature in many electricity markets. Vertical integration of generation and retail reduces the incentives to trade on wholesale markets. Low levels of liquidity are an entry barrier. The strong links between supply and network companies reduces the economic incentives for the network operators to grant access to third parties. Many respondents are highly critical of the efficiency of existing unbundling obligations, believing that discrimination in favour of affiliates continues, and calling for stricter measures.

Market integration:

The low level of cross-border trade is insufficient to exert pressure on (dominant) generators in national markets. Integration is hampered by insufficient interconnector capacity and long-term capacity reservations predating the liberalisation. Improving access to interconnectors requires better methods of congestion management. There is also a lack of adequate incentives to invest in additional capacity to eliminate long-established bottlenecks. Different market designs hamper market integration.

Transparency:

There is a serious lack of transparency in the electricity wholesale markets that is widely recognised by the sector. Improved transparency would minimise risks for market players and so reduce entry barriers to generation and supply markets, provide a level playing field, and improve trust in the wholesale markets and confidence in its price signals. More than 80 percent of market participants are not content with the current levels of transparency. Users request more information on technical availability of inter-connectors and transmission

networks, on generation, on balancing and reserve power, and on load. Rules on proper market conduct and supervision differ significantly between Member States, as there is little harmonisation at EU level of the transparency requirements in electricity markets.

Price formation:

Price formation is complex, and many users have limited trust in the price formation mechanisms. Fuel price increases in marginal plants certainly play a role in recent electricity price developments. Gas prices have significantly increased but coal prices have remained relatively stable. Analysts cannot yet agree on the extent to which the EU emissions trading scheme has affected electricity prices. The co-existence of regulated and free market prices on several national markets has an adverse effect on the development of competitive markets. In a number of Member States, special measures to reduce electricity costs for large energy intensive users have also been considered, although compatibility with antitrust and state aid rules provides limits to lowering prices by such schemes.

Way forward

In the Issues Paper the Commission services had announced that it would discuss and propose any necessary *structural, regulatory and competition law based remedies,* once the assessment of the findings of the Inquiry and the parallel reviews of implementation of the Liberalisation Directives had been concluded. It is therefore **too early to draw conclusions** at this stage and comments are solicited during the forthcoming two months consultation period following the publication of the report and the **wider debate in the context of the forthcoming Green Paper**, which will allow the Commission to reach conclusions at the end of 2006. Nevertheless, from the point of view of the Commission services a number of preliminary remarks can be made now.

Competition law

The Commission is pursuing infringements of Community competition law in the sector wherever the Community interest so requires, in accordance with the regulations in place and in close cooperation with National Competition Authorities. Even before the completion of the Inquiry, the current findings will help to carry forward procedures with full knowledge of the market environment and to orient priorities towards the most serious problem areas.

(1) *Market Concentration* has been identified as the major problem and this makes the Community's action under the merger regulation essential. While each merger case is assessed according to its specific characteristics, the Inquiry helps to identify the most relevant criteria and the most efficient remedies in the given market environment.

(2) *Vertical foreclosure: Tying of downstream markets.* The Inquiry has confirmed that foreclosure of the downstream market by long-term contracts is an immediate priority for review of case situations under competition law. During the forthcoming phase of the Inquiry, the data collected will be further screened and any foreclosure effect closely analysed.

(3) *Market integration: access to capacity on pipelines, gas storage and on interconnectors* has been found to be a major stumbling block towards more market integration and should be the other immediate priority for review in terms of anti-competitive conduct.

The findings indicate that the use of market partitioning clauses continues in a number of Member States. This will need further attention during the final phase of the Inquiry.

Besides these priority actions focusing on market concentration, downstream market foreclosure, and market integration, other case situations of anti-competitive and exclusionary conduct deserve immediate attention, such as inhibiting customers from switching suppliers.

The issuance of guidance on the application of Articles 81 and 82 EC to various practices in the sector may be envisaged. The Commission welcomes comments on the need for such guidance during the consultation.

Regulatory

The Commission has undertaken to review on a Member State by Member State basis the implementation of the gas and electricity liberalisation directives during 2006, and to submit proposals by the end of the year[4].

While more time will, therefore, be needed to reach conclusions in this field, from a competition perspective a number of issues already seem to emerge from the preliminary findings.

(1) A main finding is that *transparency* is insufficient in the sector. There seems to be broad consensus that this issue should be addressed by strengthening transparency obligations, be it under regulation or under competition law.

(2) There are substantial indications that the remaining "*grandfathering rights*"[5] seriously impede effective entry of competitors and therefore undermine the pro-competitive operation of the market.

(3) Whilst progress has been made in fixing common rules regarding the interconnectors between national grids, much more needs to be done. While there are a number of schemes between national regulators in place or being set up concerning coordination in this area, the findings suggest that purely voluntary cooperation schemes between regulators are unlikely to provide the investment certainty and regulatory protection that is needed to develop international pipelines and interconnectors in a stable environment and keep them open.

There are a number of other regulatory issues that have been raised by both market participants and regulators and which will have to be further considered during the ongoing reviews of the implementation of regulation in the sector. It seems that in a number of Member States, the powers of national regulators should be increased in a number of areas. For example, one area appears to be the surveillance of the conditions and prices for Third Party Access for competitors in order to make pro-competitive markets work and allow consumers to benefit.

Issues under review

There are a number of issues on which it would be premature to take position at the current stage of the assessment but on which comments are solicited:

[4] Commission Report on Progress in Creating the Internal Gas and Electricity Market, 15 November 2005

[5] Capacity rights stemming from pre-liberalisation monopoly contracts.

- price setting practises on electricity wholesale markets including power exchanges,

- the competitive assessment of the gas / oil price linkage in many contracts,

- the exemption from Third Party Access provisions in the gas directive (in cases of new investment in pipelines, storage and LNG terminals),

- a possible more generalised use of gas and electricity release programmes under regulation, in order to reduce the effect of concentration in the upstream supply level and inject liquidity into the market, as well as other measures reducing the effects of concentration,

- further measures to reduce upstream supply concentration, and

- the impact of the Emission Trading System (ETS) on prices in the electricity market. The Emission Trading System is central to a cost effective attainment of the Kyoto green house gas reduction goals and therefore must be seen in a wider policy context. The Commission has committed to undertake a review of the functioning of the scheme before the end of the year.

Structural

While the measures and issues set out above and submitted for consultation would address a number of the key problems found at this stage of the Inquiry, the findings of the inquiry suggest more and more strongly that a real breakthrough towards effective competition in the gas and electricity markets by 1st July 2007 will not be possible unless the root causes of the market malfunctioning are addressed. The market structure suffers from a systemic conflicts of interest resulting from the vertical integration, in many cases, of the supply, transport and distribution level.

This situation dates from the pre-liberalisation period and prevents the advantages of an efficient competitive market reaching the final consumer in a meaningful manner. It makes the Community's energy system less receptive to the introduction of new forms of energy such as renewables due to the stake holders' interest at all three levels of the value chain; and it prevents an effective diversification of supply, which is an indispensable element towards more security of supply.

The provisions of the second electricity and gas Directives on unbundling need to be fully implemented, not just in their letter but also in their spirit. If real progress in this respect does not develop and a true level playing field result, further measures such as **full structural unbundling** (i.e. separation on the supply and retail business from monopoly infrastructures) should be considered.[6]

Comments on this issue are also welcome during the consultation period.

[6] Member States are addressing the issue of unbundling under the existing Directives and national regulation along different routes. Certain Member States have introduced full “ownership unbundling”.

Conclusion

The overall objective of the Inquiry was to identify the barriers currently impeding the development of a fully functioning open and competitive EU wide energy market as a basis for fairer prices for the final consumer, more efficient allocation and use of resources and supply, more openness for renewable energies and an economically sustainable basis for security of supply.

At this stage of the preliminary findings, the overall conclusion is that the main problem areas identified in the Issues Paper have been confirmed. Comments are solicited on these problems and the further considerations submitted in this Preliminary Report before 1st May 2006 and should be sent to comp-energy-sector-inquiry@cec.eu.int. Taking account of comments received and the further assessment of data, the Final Report on the Inquiry will be published at the end of 2006.

A. INTRODUCTION

(1) Well functioning energy markets that ensure secure energy supplies at competitive prices are key for achieving growth and consumer welfare. To achieve this objective, the EU has decided to open energy markets to competition allowing for European market integration. This process of gradual market opening has significantly changed the functioning of the markets, provided new market opportunities and initially lowered energy prices in Europe. Nevertheless, the objectives of market opening have not been fully achieved and the initial price decreases have been undermined by dramatically rising prices, notably in 2005.

(2) Significant rises in gas and electricity wholesale prices and persistent complaints about barriers to entry and limited consumer choice led the Commission to open an inquiry into the functioning of the European gas and electricity markets in June 2005. The inquiry, based on Art. 17 of Regulation 1/2003, aims at assessing competitive conditions and establishing whether current indications of market malfunctioning result from breaches of competition law.

(3) When analysing the gas and electricity markets, the broader implications of the development of these sectors should be kept in mind. Both the European consumer and European industry[7] are heavily dependent on the secure and reliable provision of energy at competitive and fair prices. Also, the achievement of the Union's goals for the environment is closely linked to reducing greenhouse gases in the energy sector and meeting the Kyoto commitments.

(4) The wider context has been set out in the Commission's Communication[8] to the 2006 Spring European Council concerning the renewed Growth and Jobs strategy, that puts the formulation of an efficient and integrated energy policy at the heart of the Commission's priorities. This context will be further developed in the announced Green Paper towards an integrated European Energy Policy, to be submitted by the Commission in early March 2006.

(5) Whilst there are similarities between the gas and electricity sectors – not least when it comes to the unsatisfactory state of the liberalisation process - there are also some important differences. The main differences are: (a) electricity is not a natural resource, whilst gas is (i.e. electricity can in principle be produced everywhere in the Community whilst gas can only be produced where found); (b) electricity cannot be stored whilst gas can; (c) electricity generators have a more direct impact on prices through different marginal costs (e.g. for base load and peak load) than in gas; (d) liberalisation in electricity started at EU level earlier than in gas. These and other differences have to be taken into account when describing the state of liberalisation of the gas and electricity markets.

(6) Little reliable quantitative data is available on many aspects of electricity and (especially) gas markets. A thorough market investigation was therefore needed as a basis for the assessment of energy market functioning. The Commission sent out over

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7 As noted above, the Commission's October 2005 Communication on the Lisbon programme has led inter alia to the creation of a High Level group on competitiveness, energy and the environment.

8 Time to move up a gear - Annual Progress on Growth and Jobs, Communication from the Commission, 25 January 2006.

3000 questionnaires in the summer 2005 in order to establish the facts for a solid competition analysis. This makes the sector inquiry one of the most thorough investigations in the Commission's history.

(7) An Issues Paper setting out initial findings was prepared in November 2005[9]. In particular, five areas of possible market malfunctioning were identified in the Issues Paper:

- gas and electricity markets in many Member States continue to be concentrated, creating scope for incumbent operators to influence prices;
- wholesale markets are not liquid: either because of vertical foreclosure due to long term contracts (gas); or because companies are active both in generation and retail, limiting the development of wholesale markets (electricity). There is an inadequate level of unbundling of network and supply activities;
- barriers to the cross border supply of gas and electricity prevent the development of integrated EU energy markets;
- a lack of transparency on the markets aggravates mistrust in market functioning and benefits incumbents, undermining the position of new entrant;
- there is little trust by industry and consumers in current price formation mechanisms on electricity and gas wholesale markets, and prices have increased significantly.

(8) The initial indications in the Issues Paper were discussed with national competition authorities and electricity and gas regulators on 15 November 2005. The Issues Paper, which was generally welcomed, was also presented to the Energy Council in December 2005 by Commissioner Kroes. The Council discussion on the state of the Internal Energy Market also took account of the Communication from the Commission reporting on progress in creating the internal gas and electricity market[10].

(9) This Preliminary Report builds on the Issues Paper. Further analysis has been undertaken of the data gathered and these further findings have been integrated in this report. The main indications of the Issues Paper have been confirmed.

(10) As in the Issues Paper, the main concerns for the gas and electricity sector are therefore grouped under the five broad categories:

(1) Market concentration;

(2) Vertical foreclosure;

(3) Lack of market integration;

(4) Lack of transparency; and

[9] The Issues Paper is available on the DG Competition website, at http://www.europa.eu.int/comm/competition/antitrust/others/sector_inquiries/energy/.

[10] COM (2005)568, November 2005

(5) Price issues.

The main findings for both sectors are set out in the Conclusions of this report. It should be noted that at this stage the findings are preliminary. Further consolidation and confirmation is expected from the continuing review by the Commission of the sector, the completion of our assessment of data collected, and comments. After completion of this further assessment, the Final Report on the Inquiry will be published at the end of 2006.

B. GAS

I. Introduction

I.1. Main market features

Gas production, supply and transport

(11) Natural gas is a "primary" source of energy consisting of hydrocarbons (mainly methane)[11]. It is used in industrial processes as fuel and raw material, for electricity generation, and by households for cooking and heating. Other energy sources can often be used for the same purposes. Substitution is nevertheless partial and imperfect. Changing from one energy source to another can often give rise to important switching costs.

(12) Natural gas consumption in 2003 amounted to 478 billion cubic metres (bcm) in the European Union. It accounts for approximately a quarter of primary energy consumption by type of fuel. The most important European gas markets are: UK (consumption 101 bcm), Germany (93 bcm) Italy (74 bcm) and France (46 bcm)[12].

(13) Around 42% of the natural gas consumed in the EU is produced within the EU, in particular in the United Kingdom, the Netherlands and Denmark, as well as in Italy, Poland and Germany[13]. This means that the EU currently imports around 58% of its gas needs, and this proportion is growing. The following graph shows increasing gas consumption in Europe since 1985 for all current Member States, as well as the increasing share of gas imports from third countries. Between 1985 and 2004, imports have increased from roughly 40% to 60% of consumption.

(14) Gas prices have risen sharply in the last few years. This is true both for gas imported on the basis of long term contracts with an oil-price link (Figure 2 shows prices at some key EU border crossings) and prices on the few traded markets (some gas hub prices are shown in Figure 3) in Europe.

(15) The natural gas industry links together several separate physical or commercial activities: 1) exploration for and production of gas; 2) international transport of the gas to the region of consumption (EU) through pipelines or by sea in liquefied form; 3) wholesale supply within the EU (bilateral or trading at hubs); 4) national transport in transmission networks; 5) ancillary services, notably storage and blending; 6) supply to end-consumers; 7) transport at distribution level; and 8) ancillary services to end-customers (metering, billing, etc.).

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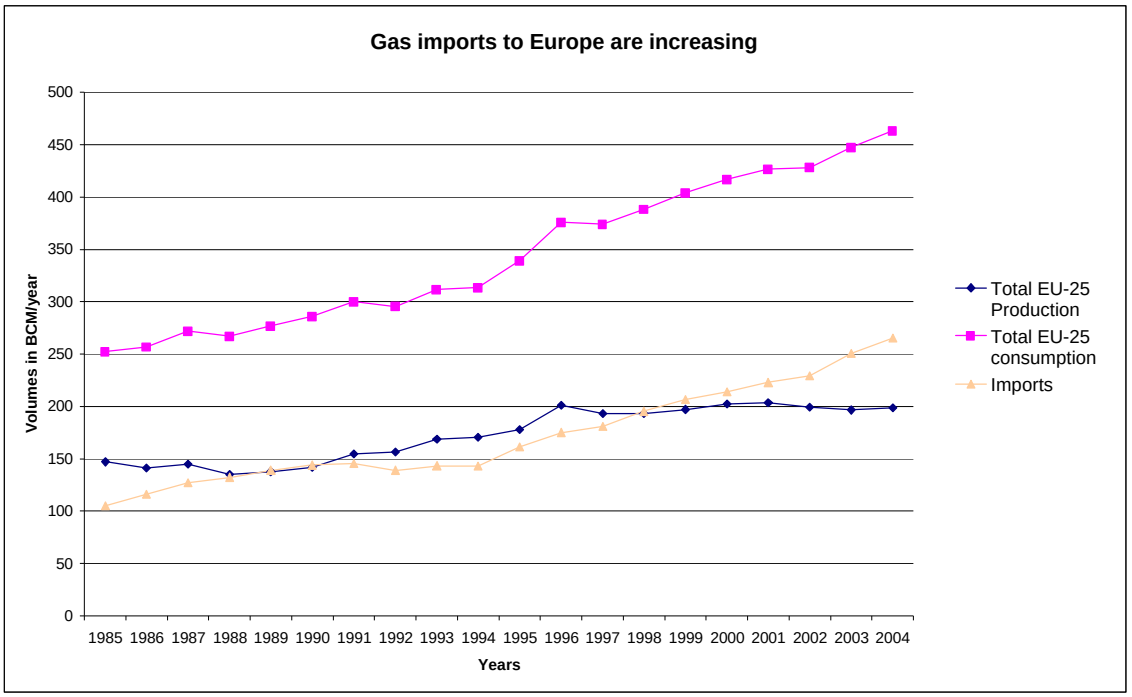
11 Natural gas is not a fully homogenous product and technical quality differences can be important. In Europe a main distinction can be made is between so called H-gas (high calorific value), which is the most widely produced type of natural gas, and so called L-gas (low calorific value).

12 Source: Eurostat, gross inland consumption data for 2003. The BP Statistical Review 2005 provides data up to 2004, and estimates slightly lower consumption.

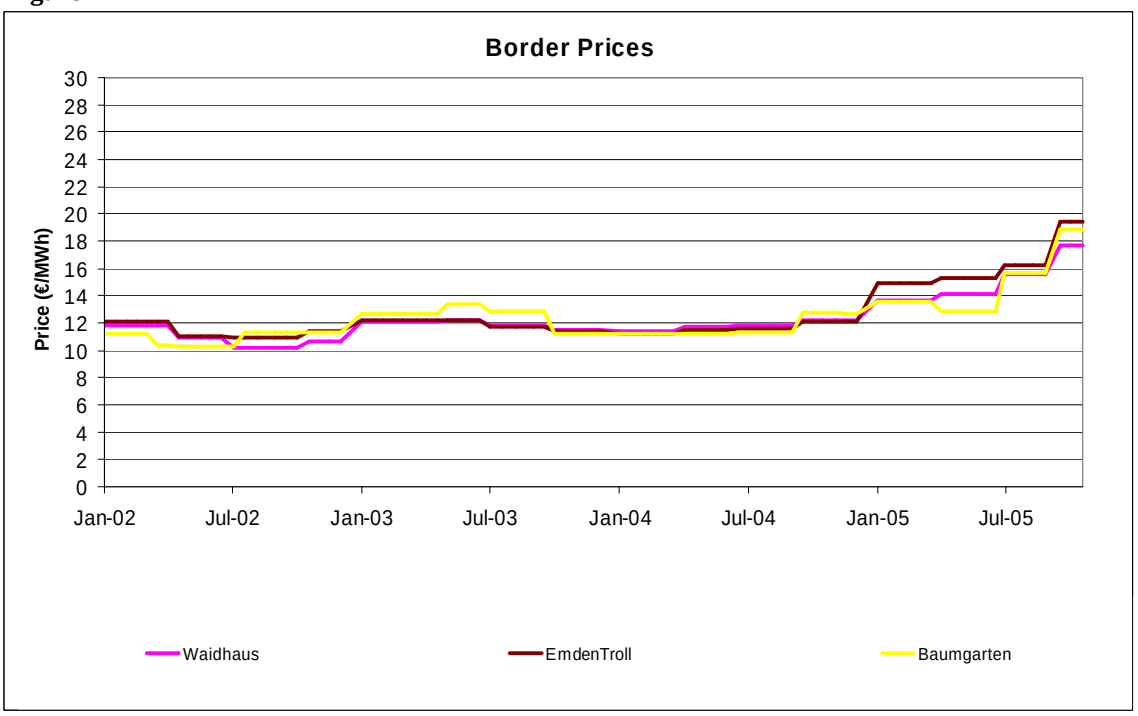
13 Calculations on the basis of the BP Statistical Review 2005 indicates that in 2003, 45,8 % and in 2004, 44,8 % of the gas consumed in the EU was produced in the EU.

Figure 1



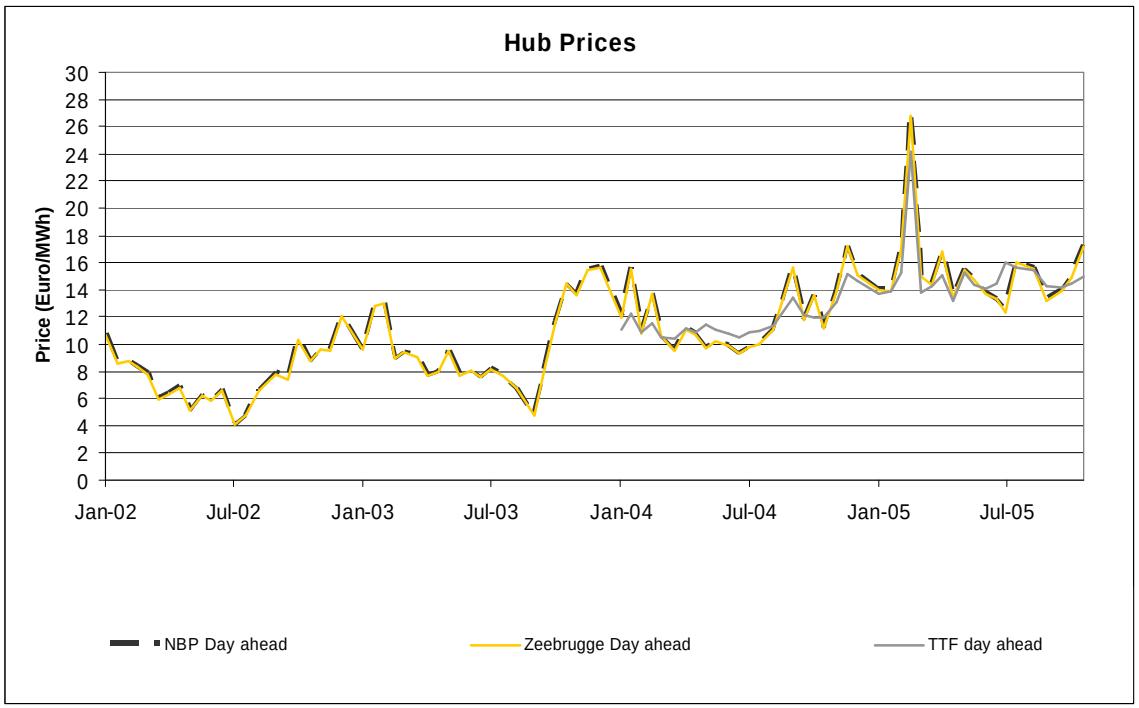
Source: BP Statistical Review 2005

Figure 2



Source: Heren European Gas Market

Figure 3



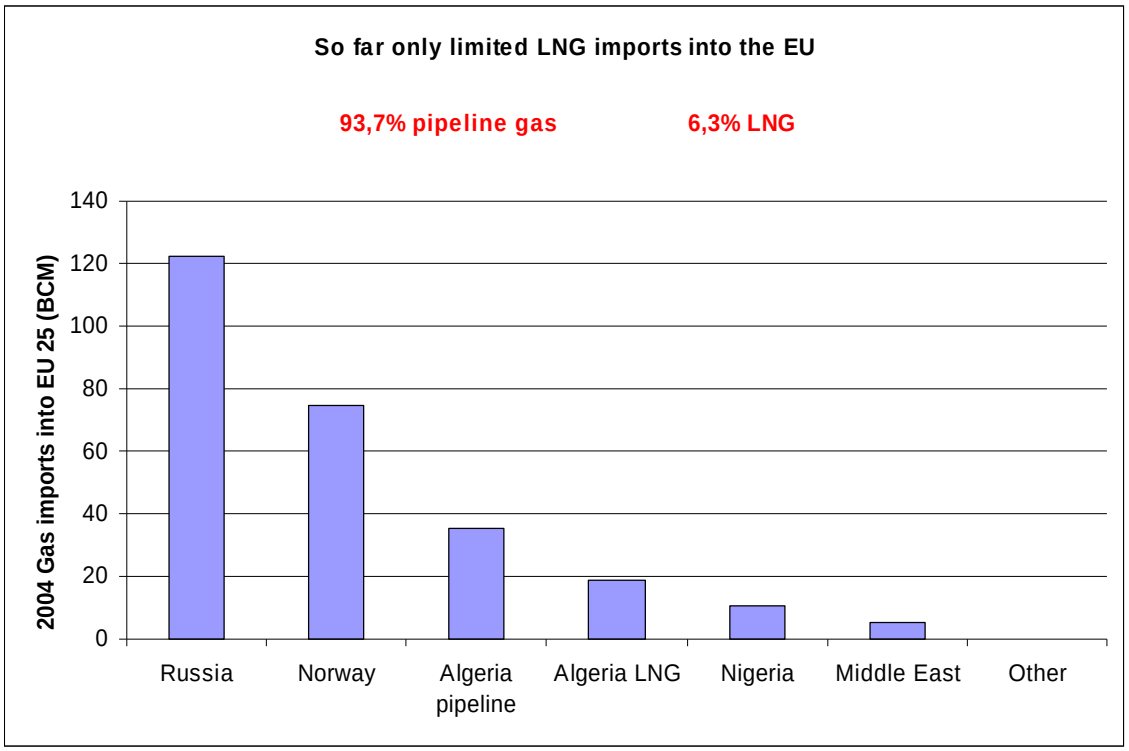
Source: ARGUS

(16) Natural gas is found in underground reserves. For geological reasons gas extraction may be more or less flexible. From some fields the gas must be extracted at a continuous rate and there is limited margin to influence the production rate, without jeopardising the overall volume of gas available. Other fields do not allow control of the rate of gas production because gas is merely a by-product of oil production. Flexible gas fields have different economic characteristics, since they can often be used as a source of market flexibility in competition with storage. Therefore, their value relates to the expected value of gas during future peaks.

(17) Natural gas is mostly transported from production to the markets through pipelines. Cooled and condensed it can be transported in liquefied form (LNG) by sea. Compared to other primary energy sources, transport costs for gas are high in relation to the price of the commodity. This is a key reason why gas markets have remained regional in character. Transport by pipeline remains less expensive than LNG-shipments for shorter distances. However, decreasing costs for the LNG chain have made longer transport routes economically viable, bringing new sources of gas to the European markets. This may mean that LNG becomes a viable alternative, displacing gas from longer pipeline routes. Nevertheless, many specific geographic factors play a role, and new pipelines are being considered to bring gas from relatively remote areas to Europe (e.g., the proposed Nabucco project that could transport gas from the Caspian region and Iran).

(18) Roughly 230 bcm were imported to the EU in 2004 by pipeline, whereas only 35 bcm were imported as LNG-shipments. The majority of imports come from the three major gas producing countries close to the EU: Russia, Algeria and Norway. The following graph illustrates that the major part of EU's gas imports comes from Russia and Norway. This gas flows via pipeline, whereas Algerian imports are partly transported as LNG.

Figure 4



Source: BP Statistical Review 2005

(19) The number of upstream producers supplying EU gas markets is gradually increasing as LNG supplies become more competitive and new LNG-terminals are built in Europe. This diversification of upstream supply should enhance competition between exporters to EU gas markets.

(20) Increasing LNG-imports will contribute to the globalisation of gas markets and strengthen links between the EU and US markets. LNG-imports are also expected to grow in the US and a number of facilities allowing for LNG-imports are planned. Countries like Qatar, Algeria, Trinidad or Nigeria can already supply LNG both into the EU and into the US.

(21) As a consequence of increased LNG-shipments around the Atlantic Basin[14], increased competition for short-term LNG between the US and EU can be expected. LNG quantities originally foreseen to be delivered into the EU might be diverted to the US when better profits can be made[15]. In assessing the effect of US prices on EU markets it must, however, be kept in mind that most EU imports are based on long term contracts. This is also true for LNG - supplies to Europe, which means that these gas flows are not totally flexible in reacting to changing market conditions. Nevertheless, it cannot be excluded that short-term LNG might become the marginal unit of supply during certain periods in some markets, which might create a link to US prices. Even so, pipeline gas prices are currently often indexed to oil products. These gas imports therefore do not react to changes in the market price of gas on global markets.

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14 LNG shipments from the Atlantic to the Far East, which is the other main global source of demand for LNG, are currently marginal, but may be an important future development.

15 This trend could be reinforced by continuing high US gas prices. At present the US is short of both gas and LNG import facilities, leading to structurally high LNG-prices. US spot prices may be sent higher still by temporary phenomena, such as this year's loss of gas production in the US due to the hurricanes in the Gulf of Mexico.

(22) Onward transport from the point of import to consumers within the EU takes place by pipeline networks, which gives the gas industry the character of a network industry. The supply of gas to customers in fact depends on the possibilities to use existing pipeline infrastructure. In most cases, the construction of competing parallel gas networks is not economically viable: the network operator on a given transport market can, therefore, often be considered to be in control of a natural monopoly.

(23) The pipelines to bring gas from a production region to the European market are generally specific to that purpose. In this respect pipeline investments often constitute a sunk investment and create an interdependency between the supplier and the market served by the pipeline. The same is true of some of the investment in LNG-facilities, although to a much lesser extent, as shipments can be brought to alternative markets.

(24) The largest-volume and/or highest pressure pipelines are typically used to transport gas over long distances between or within Member States. These networks are called transmission networks, and those that are used to transport gas between and across Member States are also often referred to as transit networks.

(25) Transmission networks are generally interconnected so that inputs or off-takes at one point affect the rest of the network to some extent. The very high and relatively stable flow rates often associated with transit lines have meant that operational arrangements have historically developed somewhat differently to those applying to transmission networks. For instance, some transit pipelines are interconnected with a wider network only to a limited extent, and can be managed on an end-to-end basis.

(26) Connected to off-take points from transmission networks are lower-pressure networks, called distribution networks. The majority of end-customers are connected to distribution networks, although some large users connect directly to transmission networks. Distribution system operators (DSOs) are generally also responsible for metering their customers' consumption, and therefore in competitive markets often have a vital role in ensuring the availability of accurate consumption data and in ensuring a smooth customer transfer between suppliers.

(27) The off-take of individual users of gas varies in ways which might be predictable (e.g., space heating in homes will consume more gas in winter than in summer; and might be turned down at night), or less so (e.g., if a production line breaks down). Gas supply therefore needs to be flexible: it must have a seasonal and daily shape, and it must also be able to adjust to unexpected changes in demand[16].

(28) Flexibility of gas supply can be assured in a number of ways. Flow change may be secured through turning up or down particularly flexible gas fields. Storage facilities allow gas to be stored, which means that production and demand do not need to be in balance in the same way as for electricity. Balancing inflows and outflows over the short term is nevertheless necessary to ensure system integrity of the gas network, although there is a certain margin to alter the pressure in gas pipelines.

(29) Gas infrastructure is designed to operate safely within defined quality and pressure parameters. Transmission system operators (TSOs) have access to a range of facilities to ensure this (e.g., blending facilities to ensure appropriate quality; storage, compressors

[16] The concept of flexibility is used here to include both planned "shape" and responsiveness to unexpected events.

and linepack[17] to maintain safe pressures). However, as markets develop TSOs should have alternatives for maintaining safe operating conditions through their interactions with other market players, and would not necessary have to own all of the technical facilities to ensure system balance.

(30) Storage facilities offer different degrees of flexibility, because their physical characteristics often limit the speed with which gas can be injected or withdrawn[18]. For this reason, some storage sites are most suitable for seasonal storage (being filled steadily during the warmer months, so as to partly equalize winter and summer imports, which means less investment in pipelines is required), although others permit quicker injections or withdrawals. Access to storage is of particular importance to serve customers who require gas deliveries that vary over time, and in general is essential to serve household customers.

Gas market operators

(31) Gas exploration and production (E&P) requires geological and engineering competences quite different to the rest of the value chain. Therefore, although in some cases E&P is carried out by companies that are also active lower in the chain, there are not necessarily great synergies in combining production and other activities. The production companies operate on a scale that is often global. In planning development of a field, they would typically consider selling the gas to any country or company, although the economic range is influenced by transport mode and distance[19]. Many European national importers have also bought gas from several producers, notably to guarantee security of supply.

(32) Historically, gas producers' main partner within each European Member State has been a national monopolistic importer. This company might have helped to fund the construction of long-distance import infrastructure, and has also in most cases built the national transmission network and national storage facilities. In a few Member States more than one company had this kind of role, within separate geographic regions. In some cases, this incumbent importer also had a monopoly on sales to end-users in the Member State's territory. In other cases, the incumbent importer had long-established business relationships with downstream monopolies, or with other companies that in turn sold to downstream monopolies[20].

(33) Market opening puts into question vertically organisation, which was the guiding principle of the previous market structure. In principle, a range of new business models should be possible in the gas supply chain and new entrants should be able to compete on only some parts of the value chain. Notably, shippers/suppliers should be able to buy gas on wholesale markets, arranging transportation with the network company, and

17 Linepack is compressed gas stored within the pipeline network, or the ability to store gas in this way.

18 For instance, storage tanks at LNG sites are typically highly flexible, salt caverns (that would otherwise be empty) also quite flexible, whereas aquifers (where the gas must be forced into porous rock, often displacing water) have their flexibility limited by the porosity level.

19 Nevertheless some fields are effectively land-locked and certain gas producing countries have to sell their gas to or at least via Russia for this reason.

20 The companies that had *de facto* or *de jure* monopolies over imports to, or sales within, a particular region will in this report often be referred to as the incumbents. In addition, and as an exception, Wingas will be considered as an incumbent because of its unique position on the German market. Conversely, "new entrant" is used mostly to refer to companies that did not have *de facto* or *de jure* monopolies in the gas industry (i.e., it includes former electricity monopolies). When considering barriers to expansion it is also relevant to examine such barriers as they apply to former gas monopolies when expanding into new territories.

signing retail contracts with end-user customers. Pure traders focus largely on buying and selling gas on wholesale markets, arranging transportation only to the extent necessary to trade on Europe's wholesale markets. Such new business models rely on the development of functioning wholesale markets, and on access to transport networks.

(34) Liberalisation legislation specifically requires separate companies for the transport activities, so as to ensure non-discriminatory market access. TSOs are required to be unbundled from competitive activities, and DSOs will have similar obligations from 2007. Effectively unbundled networks would have different incentives compared to vertically integrated companies. Whereas integrated companies might have incentives to restrict the flow of gas so as to keep the price of gas high, independent networks would have incentives to maximise the amount of capacity sold because their profit would depend purely on transport incomes.

(35) It should also be noted that the networks are regulated, which means that their profitability and solidity are not directly determined by markets. The profitability is both capped and "guaranteed" by the regulatory system. Their financial solidity (balance sheet) depends also on the way that unbundling has been implemented.

I.2. The regulatory framework

(36) The main objective of European energy policy in the area of gas has been the gradual liberalisation of the sector and the creation of a competitive integrated internal market, with security of supply ensured at a reasonable price. The Community legislative process of liberalising the gas markets began in the 1990s, first with the Price Transparency Directive[21] and with basic non-discrimination requirements in the Transit Directive[22] and the Hydrocarbons Directive[23], and then, under the first Gas Directive[24], with the abolition of import monopolies, gradual market opening, accounting unbundling for vertically integrated network companies, and an option of regulated third party network access.

(37) The second Gas Directive[25] was adopted in June 2003 and was to be implemented by 1 July 2004, although implementation has been late or otherwise unsatisfactory in many Member States[26]. It requires full market opening, national sector regulators, regulated third party network access, regulated or negotiated access to storage and further unbundling of integrated companies. It is complemented by the Gas Regulation[27], which expands on several of the provisions in the Directive. It introduces qualitative minimum requirements for access to transmission systems (network tariffs, third party access services, capacity allocation, transparency, balancing and trading of capacity rights).

(38) Community legislation is supplemented by other binding and non-binding instruments, such as Community guidelines (under the Gas Regulation), voluntary guidelines developed within ERGEG[28] and the Madrid Forum[29] (e.g. Guidelines for Good Third Party Access Practice for Storage System Operators – GGPSSO) and technical standards prepared by EASEE-gas[30].

(39) In order to increase competition on a liberalised market, the second Gas Directive requires full market opening. All commercial customers must be free to choose their supplier by 1 July 2004, while, for household customers, the corresponding date is 1 July 2007. By that date, at the latest, the retail market should, consequently, be fully

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21 Directive 90/377/EEC of 29 June 1990 concerning a Community Procedure to improve the transparency of gas and electricity prices charged to industrial end-user (OJ 1990 L 185/16).

22 Directive 91/296/EEC of 31 May 1991 on the transit of natural gas through grids (OJ 1991 L 147/37). Repealed by the second Gas Directive.

23 Directive 94/22/EC of 30 May 1994 on the conditions for granting and using authorizations for the prospection, exploration and production of hydrocarbons (OJ 1994 L 164/3).

24 Directive 98/30/EC of 22 June 1998 concerning common rules for the internal market in natural gas (OJ 1998 L 204/1). Implementation in national law by August 2000. Repealed by the 2nd Gas Directive.

25 Directive 2003/55/EC of 26 June 2003 concerning common rules for the internal market in natural gas (OJ 2003 L 176/57). Replaces the first Gas Directive.

26 See Communication from the Commission reporting on progress in creating the internal gas and electricity market, COM (2005) 568. The Commission has also opened infringement cases against certain Member States. See also below on late implementation for specific aspects of the Directive.

27 Regulation (EC) No 1775/2005 of 28 September 2005 on conditions for access to the natural gas transmission networks (OJ 2005 L 289/1). Date of application of entry into force is 1 July 2006.

28 The European Regulators Group for Electricity and Gas established by Commission Decision of 11 November 2003 (OJ 2003 L 296/34).

29 The European Gas Regulatory Forum ("the Madrid forum"); participants include national regulatory authorities, Member States, the European Commission, network operators, gas suppliers and traders, consumers, network users, and gas exchanges.

30 The European Association for the Streamlining of Energy Exchanges, a group made up of representatives of different gas actors, provides Common Business Practices for technical harmonisation.

open to competition (although several Member States have already now introduced full market opening)[31].

(40) The Community legislation does not include measures that directly address the concentrated market structure inherited from the monopoly era, which remains a key problem of the internal gas market. In certain Member States further measures have been introduced to tackle concentration (e.g. gas release programs or market share caps).

(41) The supply of gas to final customers depends on the possibilities to use existing transport infrastructure, which can in many cases be considered as a natural monopoly. A regulatory framework is, therefore, essential to ensure that access is granted in a non-discriminatory and transparent manner.

(42) To ensure the implementation of the regulatory framework in this respect, the second Gas Directive requires the creation of national energy regulators[32]. Their main roles include approving and controlling tariffs (or tariff methodologies), ensuring non-discriminatory network access and effective unbundling, and dealing with complaints.

(43) Regulated third party access, based on approved and published tariffs, now applies to transmission, distribution and LNG operators, as well as to balancing services (i.e. negotiated access is no longer allowed). The operators must refrain from discriminating between system users, and provide them all with the information needed for efficient access.

(44) However, regulated access to necessary infrastructure is far from universal. Member States still retain a choice between applying negotiated or regulated access for storage, line pack and other ancillary services. Derogation from third party access rights, whereby investors can reserve the capacity for themselves, can also be granted in order to provide incentives for risky investments in important new infrastructure. The second Gas Directive foresees a number of criteria to be fulfilled in order to allow such exemptions including the condition that competition is not negatively affected. Such derogations may be limited in time and to a part of the capacity.

(45) In order to improve access, and reduce risks of discrimination and cross-subsidy, the second Gas Directive requires the unbundling of integrated network operators. Transmission and distribution system operators must, in addition to the previous accounting unbundling (i.e. the keeping of separate accounts), also be legally unbundled and management unbundled (i.e. independent from activities not related to the network operation as regards legal form, organisation and decision making). Whereas ownership unbundling is not required by EU legislation, several Member States have found it necessary also to require separate ownership of network and supply companies.

(46) Currently, unbundling requirements are more limited for distribution system operators, as the legal unbundling only has to be completed by 1 July 2007, and Member States can also exempt small distribution system operators, serving fewer than 100.000 connected customers, from the obligation of legal unbundling (but not from accounting unbundling). Moreover, only accounting unbundling is required for storage and LNG operators.

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31 Some Member States benefit from derogations as, for example, isolated or emerging markets.

32 In practice, regulators already existed in almost all Member States.

(47) The Gas Regulation provides further requirements aimed at ensuring fair access to transmission networks. Services must be offered in a non-discriminatory manner on terms that may also suit new entrants (e.g. firm and interruptible capacity; long and short-term contracts). It requires non-discriminatory capacity allocation mechanisms, congestion management procedures based on a use-it-or-lose-it principle, and a functioning secondary capacity market. Balancing rules must reflect genuine system needs (excessively stringent rules hamper new entrants), and imbalance charges must be cost-reflective, while still providing appropriate incentives for balance.

(48) Despite the increased obligations in the second Gas Directive, difficulties in accessing infrastructure remain a competition concern. Effective unbundling is one of the keys to fair access, not least in view of alleged discrimination by infrastructure companies in favour of their related supply businesses.

(49) In order to create an integrated European gas market, EU legislation needs to enable and facilitate cross-border trade. Twenty-five liberalised markets will not in themselves guarantee competition at EU-level.

(50) Under the second Gas Directive and the Gas Regulation, transit pipelines are covered by the same access rules as other transmission services. However, the continued validity of existing long-term transit contracts (negotiated under the now repealed Transit Directive) constitutes an important practical obstacle to introducing regulated access. If cross-border trade is to increase, access to transit capacity is vital, making these legacy contracts a key issues for market integration. Market integration is also hampered by limitations in the competences of national regulators.

(51) In the absence of any single cross-border regulator, national regulators must cooperate with each other in monitoring the management and allocation of interconnection capacity. ERGEG provides a forum for co-operation. However, the powers of regulators vary between Member States, since Community legislation only provides for certain minimum competencies. Moreover, the manner in which Community rules have been implemented varies between Member States, and may in some cases even give rise to regulatory vacuum – especially in cross-border situations. In addition to the requirements under Community law, there is also a considerable scope for Member States to apply their own specific national rules[33].

(52) Transparency is a necessary component of non-discriminatory access, and for ensuring a level playing field on wholesale markets. The Community legislation does not include rules on all aspects of transparency of gas markets. The Gas Regulation, however, supplements the basic transparency requirements of the second Gas Directive, and provides for certain further transparency requirements in relation to transport services. As regards storage, transparency provisions are set out in the non-binding Guidelines for Good Third Party Access Practice for Storage Operators, but not in binding EU legislation. Even within the scope of the binding Gas Regulation, the availability of information can suffer from lack of precision on the exact obligations of network operators and from exemptions aimed at protecting network users' commercial data. Specifically, it appears that the Regulation is being interpreted – in the Commission's

[33] E.g. authorisations or licences to operate gas facilities or to supply gas, planning permission for constructing new infrastructure, etc.

view erroneously – in a way that would allow important transit lines to benefit from the confidentiality exemptions.

(53) The second Gas Directive requires that prices for accessing transmission, distribution and LNG infrastructure, as well as balancing charges, are regulated (although this does not apply to storage, line pack and other ancillary network services). Nevertheless, in many Member States end-user prices are also regulated, often in a system where regulated prices co-exist with the market price (effectively capping the market price).

(54) The second Gas Directive includes certain general requirements for Member States to monitor security of supply issues. These provisions are complemented by a specific Directive[34] on security of gas supply adopted in April 2004. The Security of Gas Supply Directive requires Member States to define transparent and non-discriminatory security of supply standards that are compatible with a competitive internal gas market. A non-exhaustive list of possible instruments for security of supply is also included (e.g. storage capacity, cross-border pipeline capacities, domestic production, liquid markets, LNG facilities, diversification of supply sources, long-term contracts, etc). Member States shall define clear roles and responsibilities of market actors, and publish them, and must also establish standards to ensure supplies for household customers (e.g. for protecting against temporary disruptions and high gas demand in cold periods).

[34] Directive 2004/67/EC of 26 April 2004 concerning measures to safeguard security of natural gas supply (OJ 2004 L 127/92). To be implemented by May 2006.

I.3. Gas wholesale markets

(55) The large majority of gas consumed in the EU is bought by the incumbent wholesale players under long-term contracts from producers outside or inside the EU. As noted, these companies historically had special or exclusive rights to import and transport gas and normally controlled the major import and storage facilities.

(56) The business models of pure retail supplier/shippers or pure traders do not necessitate procurement of gas from remote regions (or their own production), provided gas is available on liquid wholesale markets. They are building from a much smaller business base (not having inherited a set of monopoly customers) and would be looking to purchase smaller quantities of gas. Traders may be less focused on a single geographic region, more interested in arbitraging price differences between regions, and therefore more interested in buying short-term tradable packages of gas and network capacity, rather than long-term supplies.

(57) Against this background, natural gas is bought and sold in a number of quite different ways at multiple levels of the wholesale market, as well as at the retail level[35]. Because of the variation of players involved in gas markets, the distinction between levels of the market is not always clear-cut. The exact meaning of liquidity on wholesale markets equally varies. Considering the current stage of EU gas market development it is not necessary to use any refined definition of liquidity. In the gas part of this report we use the term broadly, to mean a level of market activity that ensures a counter-party can generally be found to enable the buying or selling of gas in sufficient volumes to meet a commercial need, and at competitive prices.

(58) Some trading at wholesale level takes place through more-or-less organised markets, generally referred to as "hubs". This kind of trading is potentially more accessible to new market entrants and the non-integrated business models referred to above. It has been so far slow to develop, but the future development of traded wholesale markets is crucial for market integration and competition in EU gas markets.

(59) Developing liquid gas hubs is not only vital to allow new business models to develop in gas markets and to ensure that new entrants can secure access to gas at wholesale level. Liquid hubs would underpin the functioning of the market in many ways. They would provide a price formation mechanism that reflected supply and demand, and therefore create price signals for investment (which in turn would strengthen supply security). They would enable supplies to optimise their portfolios in a cost effective manner. They would enable traders to take advantage of short-term price differentials, and this arbitrage would keep the market efficient. Arbitrage between hubs would also help integrate geographic markets. Given the usefulness of hubs, we might expect them to develop if market conditions allow. However, the converse is equally true: the absence of liquid hubs creates significant entry barriers, so hindering the development of competition.

(60) Gas hubs can be "virtual" in character, allowing trading of gas that has been physically injected into any point on a national grid. This is the case for the UK hub (NBP) and the

[35] There is also a significant level of bilateral exchange of gas between market participants. Such trading is generally referred to as "swapping" although in fact a price is frequently set for the gas exchanged and the price is not necessarily the same on both sides. The great majority of swaps are between incumbent gas companies.

recent hubs in the Netherlands (TTF) and Italy (PSV). Others are "physical", requiring gas to be transported to a particular trading point or zone. This is true for Zeebrugge (Belgium), Baumgarten (Austria) and Emden (Germany), for instance.

(61) Certain gas hubs offer transparent title-transfer facilities, standardised contracts, and brokers helping traders to match bids and offers. Some offer the assistance of a market operator to arrange the physical transport of gas between different points around the hub, or the provision of liquidity support. Other hubs consist simply of groups of flanges across which companies arrange private swaps. No European gas hub has an operator ensuring the clearing function of the market, which is common in electricity. In the most developed gas markets (UK, US), financial derivatives of gas products are traded; this also happens in some Continental markets, but is not common.

(62) The total level of activity on European trading hubs is relatively low: a balanced sample of 30 companies bought in total over 600 bcm during 2003-2004 on hubs[36], which suggest Europe as a whole sees trading churn[37] of around 1:1. However, each unit of gas within the traded part of the market might be expected to be bought and sold many times over, so this churn rate does not mean that most consumed gas has been sold on hubs. Indeed, in more competitive markets like the UK or US churn rates are many times higher. In addition, the distribution of activity across these hubs is extremely unequal and almost all trading on European gas hubs is in the UK or at Zeebrugge, which at least partly serves the UK market (see Figure 5).

(63) The UK NBP is by far the most heavily traded hub, and the UK also sees significant "beach trading" activity (where gas is traded around entry terminals of offshore pipelines), and also trading of gas forward contracts on the International Petroleum Exchange (IPE).

(64) The most important hub in Continental Europe is located at Zeebrugge. This hub is near the end of the UK-Belgium interconnector, as well as being physically adjacent to a number of sources of gas supply (LNG, North Sea pipeline, transit lines on the Fluxys network). Over past years the interconnector has typically flowed gas to the UK during the winter, and Zeebrugge trading therefore should be understood as partly meeting UK demand. It is therefore more appropriate to compare UK-related trading activity (including a proportion of Zeebrugge trading) to consumption in that country[38].

(65) Gas is traded in a number of other locations on Continental Europe, and Figure 6 shows other locations and the volumes of trading during 2003-2004[39]. The volumes of trading in these other countries are extremely low, with gas bought on these hubs representing

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[36] Sample included 30 companies including 12 incumbents, 9 entrants, 7 producers and 2 pure traders. The sample companies were located in countries with a combined annual consumption of around 360 bcm. The stated level of purchases represents all the reported purchases of our sample companies over the two calendar years, adding together trades on multiple timescales; clearly, this is far from representing the entire market. Since each unit sold must have a buyer, the imbalance between sales and purchases in the graphs that follow shows the incompleteness of the sample used for this preliminary analysis, and suggests that a sample of the entire market would include more sellers in the UK and more buyers in Continental markets.

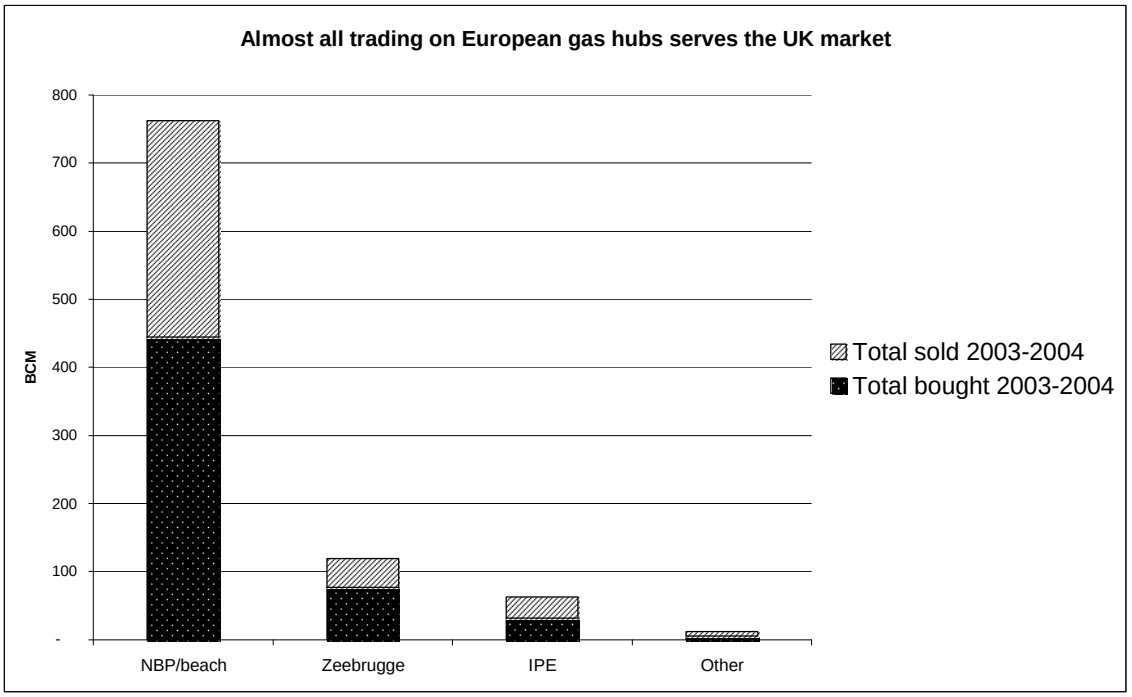
[37] "Churn" here means the ratio between total volume of trades and the physical volume of gas consumed in the area served by the hub.

[38] Gas bought in UK-related trading (by the companies analysed in the preliminary report) was around 2.6 times total UK consumption during 2003-2004, assuming that 50% of Zeebrugge activity is serving the UK market, which is probably an under-estimate. This UK-related trading represents 85% of all European hub trading reported by the same companies.

[39] Trading reported by the companies in the preliminary report sample in Belgium, the Netherlands, France, Germany and Italy.

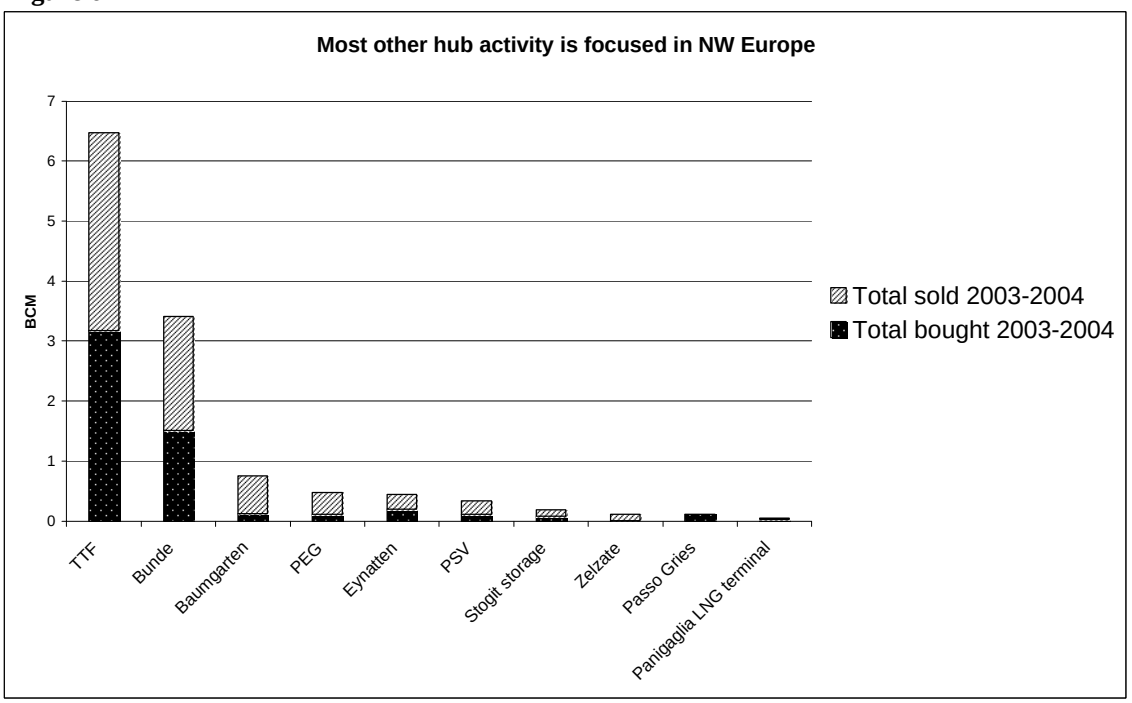
collectively only 1% of total consumption in the relevant countries[40]. Even this very limited liquidity is concentrated in North-West Europe[41].

Figure 5



Source: Energy Sector Inquiry 2005/2006

Figure 6



Source: Energy Sector Inquiry 2005/2006

40 0-7% if half of Zeebrugge trading is treated as serving the relevant Continental markets.

41 Information on trading in Spain was not collected, and it is possible that trading around LNG terminals in that country would create another significant bar on this graph.

(66) Liquidity on the hubs is caught in a vicious circle. A lack of liquidity increases the risks of trading, since it reduces the chances of finding an acceptable counter-party when a trader needs to close a position. It also facilitates price manipulation and therefore makes it more difficult to analyse and manage risk. Low liquidity therefore deters entrants (particularly pure traders), and tends to mean liquidity stays low. For these reasons, traders (e.g., banks or commodity trading houses), who have no inherent need to buy or sell gas, are largely absent from Continental hubs.

(67) It should be noted that away from the North Sea coast, trading has been reported in the answers to the inquiry in a number of locations that are not formal hubs: storage sites, LNG facilities and flanges are mentioned. Most Continental formal hubs have a number of disadvantages. The UK-related hubs, for example, are a focus for broker activity which assists with match-making and credit management, but this is not generally true with the less active Continental hubs. It could also be the case that difficulties transporting gas to hubs would deter their use, although this is less likely to be a factor for virtual hubs such as the TTF in the Netherlands or the Italian PSV. Whatever the reason, the dispersal of trading reduces the already low liquidity of individual hubs.

II. Issues

II.1. Concentration

II.1.1. Market structure

(68) The sector inquiry looks at wholesale markets with a view to assessing the competition issues that hamper the development of these markets within the EU. Competition between upstream producers outside the EU falls outside the scope of the sector inquiry, although competitive conditions on these markets influence the price of the basic commodity.

(69) There are a number of global players active on the upstream gas producer level. If the market is considered global then concentration is unlikely to be excessively high[42]. However, such a geographical delineation is difficult given that the feasibility of buying gas from various different gas producers depends on gas transport costs and the availability of gas infrastructure (notably, pipelines and LNG terminals). Due to infrastructure constraints some regions in the EU are dependant on a limited number of upstream producers for their gas. Therefore, defining this upstream market is not straightforward. However, the future development of new infrastructure and LNG sources is likely to provide new economically viable sources of gas to Europe thereby reducing dependence on a few producers and hence reducing concentration, where it exists, at this level of the gas supply chain.

(70) The sector inquiry is concerned with the competitive conditions within the EU. At the wholesale level of the gas supply chain EU liberalisation has not, so far, significantly changed the market structure. The high level of concentration which existed in most national markets at liberalisation largely remains. This is true at both the national wholesale and retail levels for most countries, although the distinction between wholesale and retail is not clear cut. In many national markets no liquid wholesale market has emerged and traded markets (gas hubs) represent a minor part of gas supply.

(71) The lack of liquidity on European wholesale markets is crucial for competition, as such markets would contribute to market integration and price formation based on the supply and demand for gas. Liquid wholesale markets also crucially affect competitive conditions at the retail level, because most new entrants wishing to enter the retail market do not have access to gas supplies directly from gas producers and so they need to procure gas on wholesale markets.

(72) For a competition analysis of market structure (concentration and market dominance) it is necessary to delineate the product and geographic dimension of the gas market[43]. This must be done on a case by case basis. The different degrees of market developments in Member States play a key role for defining the relevant market.

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42 In IV/M.1383 Exxon/Mobil , the Commission considered that there is a world-wide exploration market for oil and natural gas (as the possible contents of the ground are not known at the time of exploration) and that there is a market for the development, production and sales of gas. The precise definition of the geographic scope of this latter market was left open, even though the Commission found that the market would probably include the EEA, Algeria and Russia.

43 Commission Notice on the Definition of the Relevant Market for the Purposes of Community Competiton Law, OJC 372 of December 9, 1997.

(73) The definition of the relevant product market(s) must according to Commission practice take into account the existing and foreseen degree of market opening[44]. The fact that gas customers are captive or eligible to choose their supplies will influence their behaviour on the demand side. Eligible customers may further be subdivided into separate markets, according to their gas consumption and profiles[45].

(74) In more developed markets a separate market for wholesale supplies of natural gas can be distinguished. Amongst factors to be considered are: on the demand side, whether there is a need for gas supply at the wholesale level and on the supply side, whether there is an offer of such wholesale gas[46]. The Commission has considered that at the wholesale level, gas is supplied to local distribution companies, power generators and industrial customers. The Commission found that at the retail level, gas is supplied by local companies to final customers[47].

(75) It should also be noted that gas is not a completely homogenous product. Traditionally EU gas has been classified in two gas qualities: on the one hand, so called H-gas (high calorific value), which is the most widely produced type of natural gas, and on the other hand, L-gas (low calorific value)[48]. However, even within the most common category of H gas, technical quality differences remain, which continue to hamper cross-border gas flows, into the UK amongst others[49].

(76) It is the Commission's experience that gas supply markets are not broader than national in scope[50]. Network congestion may be an important (but not the only) constraint on the boundaries of the relevant market, since new entrants may simply be unable to gain access to a market because they cannot transport their gas to it.

(77) Besides gas supply markets, gas infrastructure operations constitute another category of relevant product markets[51]. The two main types of infrastructure operations are transportation and storage[52].

(78) Also for gas infrastructure, the geographic scope of the market needs to be defined. Where a network is owned by a sole company operating in one country or region, the

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44 See, inter alia, COMP/M.3440 EDP/ENI/GDP. Even though as of 1 July 2007, when all customers should be eligible, this distinction should become less relevant, except for countries benefiting from exemptions.

45 See COMP/M. 3318 ESC/Sibelga (December 2003) and COMP/M.3410 Total/Gaz de France (August 2004)

46 See IV/M.1383 Exxon/Mobil, COMP/M.3440 EDP/ENI/GDP, COMP/M.2822 ENBW/ENI/GVS. In Germany, a regional wholesale level has also been distinguished.

47 See IV/M.1383 Exxon/Mobil.

48 The latter type of gas is mainly produced in the large Dutch Groningen field. If there are distinct infrastructures for the supply of the low-calorific gas, high-calorific gas or gas of a different quality then this may lead to the definition of separate product markets. In IV/M.1383 Exxon/Mobil (September 1999), the Commission found that on the German market, low-calorific gas could be substitutable with high-calorific gas. In later decisions, the Commission leaned towards a different product market definition, considering that there were probably distinct product markets for L-gas and H-gas, even though it left the definition open. See, M.3075 to M. 3080 and M. 3318 ESC / Sibelga (December 2003) regarding the Belgian market.

49 EASEE-GAS has worked, within the framework of the Madrid Forum, towards harmonising gas quality standards within the European Union.

50 See COMP/M.3696 E.ON/MOL and COMP/M.3440 EDP/ENI/GDP, as well as M.3297 Norsk Hydro/Duke Energy and M. 3294 Exxon Mobil/BEB

51 See COMP/M.3696 E.ON/MOL

52 Gas transport can be subdivided into gas transmission and gas distribution. The two networks may be submitted to different legal regimes and are physically distinct, the former operating at high pressure and concerning larger volumes than the latter. Other relevant markets could be e.g. metering services, quality control services etc.

definition is rather straightforward[53]. However, the question arises whether transit lines for which no alternative exists may constitute separate geographical markets.

II.1.2. Concentration in imports and domestic production

(79) Competition brings benefits through lower prices, greater choice, enhanced efficiency and more innovation. However, highly concentrated markets may indicate that competition is not effective and therefore that these benefits are not being realised.

(80) The sector inquiry looks at wholesale markets with a view to assessing competitive conditions within the EU, not only on traded "wholesale markets", but also on the part of these markets where competition is not fully developed. In this respect it is essential to recognise that natural gas consumed in the EU comes from imports, domestic production (in some countries) or traded markets.

(81) The "wholesale level" that is considered relevant in this inquiry includes domestic production and imports on the supply side as well as traded "hubs"[54]. In some countries like The Netherlands, Italy, the United Kingdom, Germany and Denmark, where national production is (or has been) important, producers have been active themselves at the wholesale level. It should also be noted that "gas release programmes" may provide liquidity at wholesale level[55].

(82) Incumbent shares of imports and domestic production are illustrated in the table below. Incumbent suppliers source the vast majority of their gas through long-term contracts, which may relate to gas imports or to domestic gas production. The gas sector inquiry has analysed 400 of these contracts so far, representing about 360 bcm of gas in 2004. Many of these contracts were entered into at a time when incumbents were national monopolies. Long-term gas supply contracts were often linked to infrastructure development such as a pipeline or gas fired power station, since in order for the investment in such a project to be viable a long term supply of gas needed to be secured. Now incumbents retain this access to gas.

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53 COMP/M.3696 E.ON/MOL For example, in Germany there is a multi-tiered structure with about 700 local network operators, about 40 regional network operators and a few supra-regional network operators. Local supply companies, known as Stadtwerke, are often the de facto monopoly suppliers in their regions and control the local distribution network.

54 In most EU countries, short-term operations carried out at hubs are not a main feature of the wholesale markets. See introduction for further discussion of gas hubs.

55 Gas release programmes aim to give entrants access to gas by obliging incumbents to make gas available. There have been several types of gas release programmes implemented, for example in the UK, Spain, Italy, Germany and Austria, with varying degrees of success. In the UK a gas release programme was part of a package of reforms that led to the successful opening of the gas market to competition.

Table 1

Incumbents control the majority of the gas in their home countries				
	Total imports (2004, in bcm)	Incumbent share of imports (2004)	Total domestic production (2004, in bcm)	Incumbent share of domestic production (2004)
Austria	9	80-90%	2	-
Belgium	16	90-100%	0	-
Czech Republic	9	90-100%	<1	-
Denmark	0	-	10	80-90%
France	49	90-100%	1	-
Great Britain	13	20-30%	105	40-50%
Germany	88	90-100%	18	80-90%
Hungary	11	90-100%	3	90-100%
Italy	67	60-70%	13	80-90%
Netherlands	18	50-60%	73	90-100%
Poland	10	90-100%	5	90-100%
Slovakia	7	90-100%	<1	-

Source: Sector inquiry, Eurostat, National Regulatory Authorities
Note: "Total imports" means gas imported for use in domestic consumption and do not include transit gas or imports that are subsequently exported. Due to differences in countries reporting methodologies percentages are presented in ranges.

(83) For most countries represented in the table the incumbents control the vast majority of the gas either through import contracts or through control of domestic production. The exception is the UK where there has been full ownership unbundling of the former monopoly gas supply company (Centrica), the network operator (NGT) and gas production (BG Group). Here we can see that the incumbent share of domestic production and imports is relatively low. In Germany there are a few vertically integrated gas companies. Here we see a much higher concentration of the gas in the hands of the incumbents. France, Czech Republic and Slovakia have very little domestic gas production whilst Belgium has none. In these countries, therefore, the incumbents retain control of the gas through their import contracts.

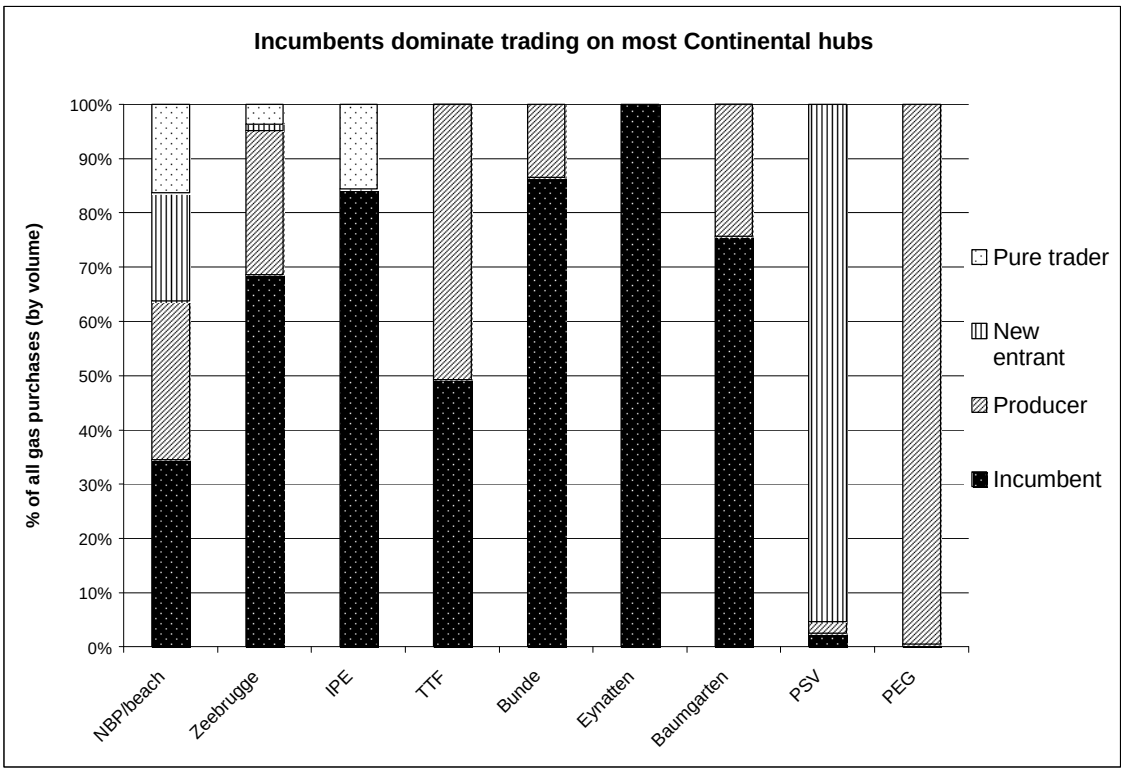
II.1.3. Concentration on traded gas markets

(84) Given that most domestic production and imports are controlled by incumbents, traded gas markets or 'hubs'[56] are an important potential source of gas for new entrants. However, the limited role of traded markets means that competitive conditions at wholesale level in gas markets are in most national markets mainly determined by the companies with access to most available gas through their contracts with gas importers and producers. The incumbents are also the major players on most of the gas hubs. The following graph shows the distribution of activity on a number of hubs between different types of company[57].

[56] Hubs are discussed in more detail in the introduction to the gas section of this report.

[57] Data in this section is based on a balanced sample of 30 companies which bought in total over 600 bcm during 2003-2004 on hubs. The data represent all products traded on hubs which including spot and forward trading up to one year ahead.

Figure 7



Source: Energy Sector Inquiry 2005/2006

(85) The majority of trading on Continental hubs is carried out by companies with established gas positions, as "pure traders" play a minor role. On each of the most important Continental hubs, incumbents were significant buyers during 2003-2004 (49% by volume of all TTF purchases, 58% in Zeebrugge, 76% at Baumgarten and 86% at Bunde). Gas producers were the next most important group of traders. New entrant suppliers bought small volumes at Zeebrugge (2% of all purchases), and almost nothing anywhere else on the continent except Italy.

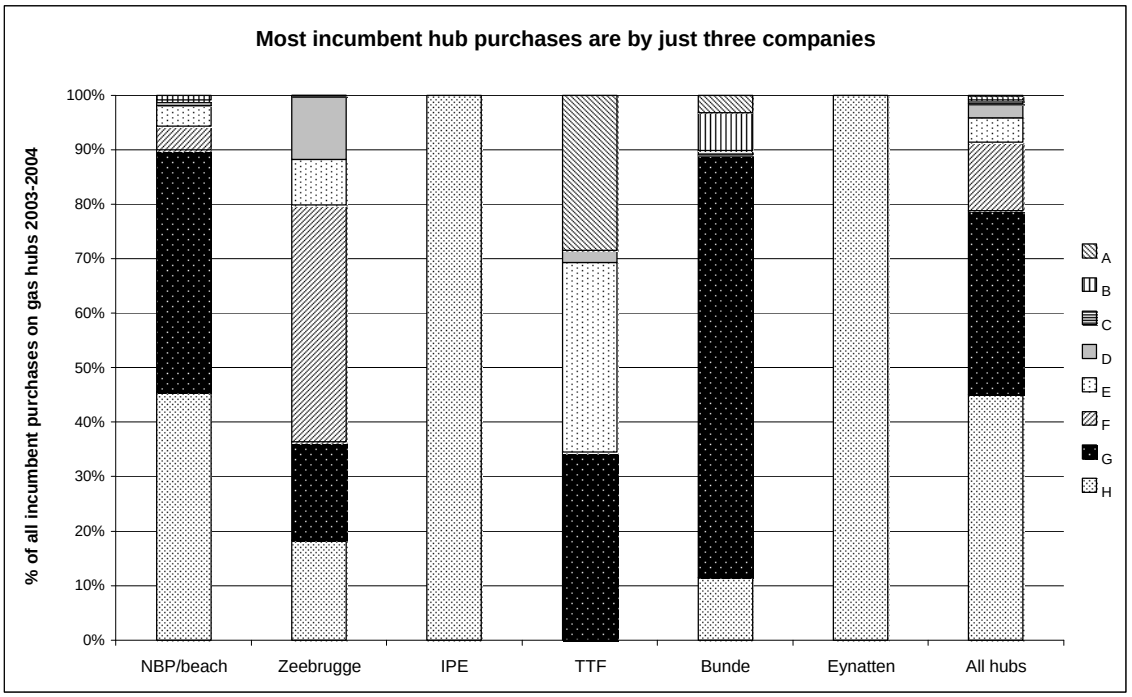
(86) Italy represents a significant exception to the general pattern. In that country incumbent and producer involvement in trading is extremely low, and therefore new entrants predominate on the PSV. However, the low volumes involved must be stressed: total purchases on PSV in 2003-2004 represented less than 0.1% of total Italian consumption.

(87) Incumbents are, then, of some importance in providing liquidity. However, the distribution of incumbent activity is sharply unequal. As Figure 8 shows, across all European hubs[58], over 90% of all incumbent hub purchases during 2003-2004 were by just three companies. One of these companies (Company F) is barely active except as a major buyer at Zeebrugge.

(88) A good deal of incumbent trading is local. For instance, Company A bought very little except on the TTF and at Bunde, which are close to its historic area of operations.

[58] To aid clarity, separate data on very small trading points (PSV, PEG and assorted flange trading) are not presented on the graph, but the "All hubs" column does include these.

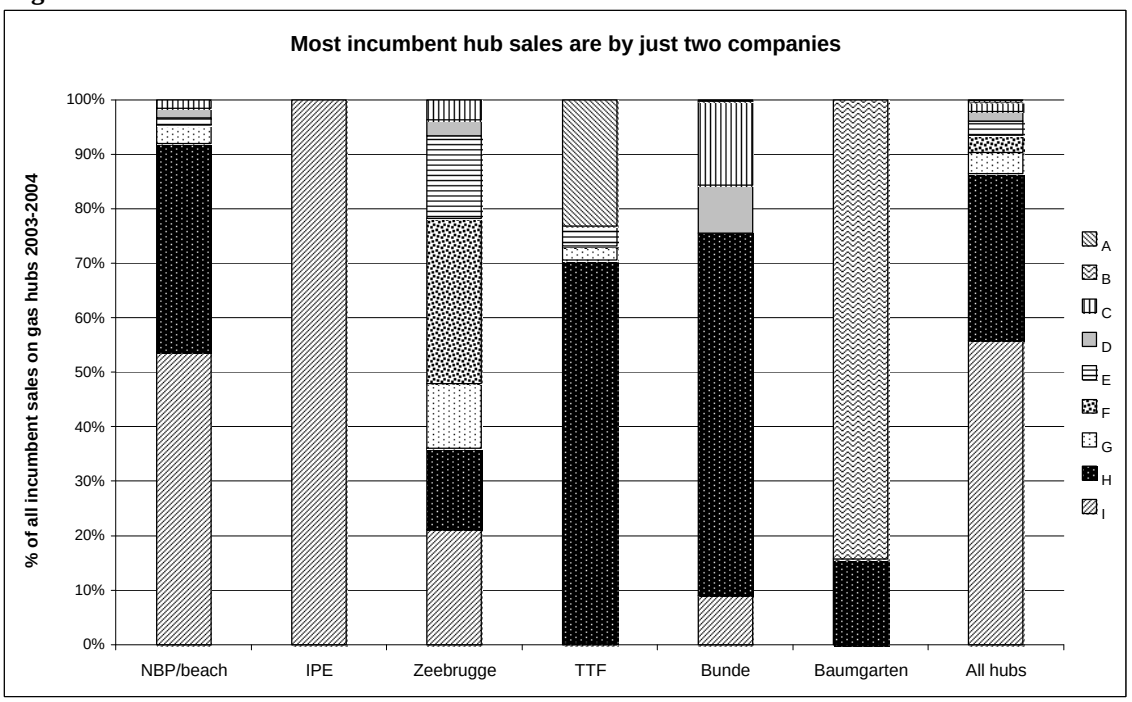
Figure 8



Source: Energy Sector Inquiry 2005/2006

(89) Data on incumbent sales on hubs (see Figure 9) show even more concentration, with just two companies reporting 87% of all hub sales in 2003-2004 (the same two as represented nearly 80% of hub purchases). Again, we see localised activity: for instance, Company B reported major sales at Baumgarten and no activity at other hubs.

Figure 9

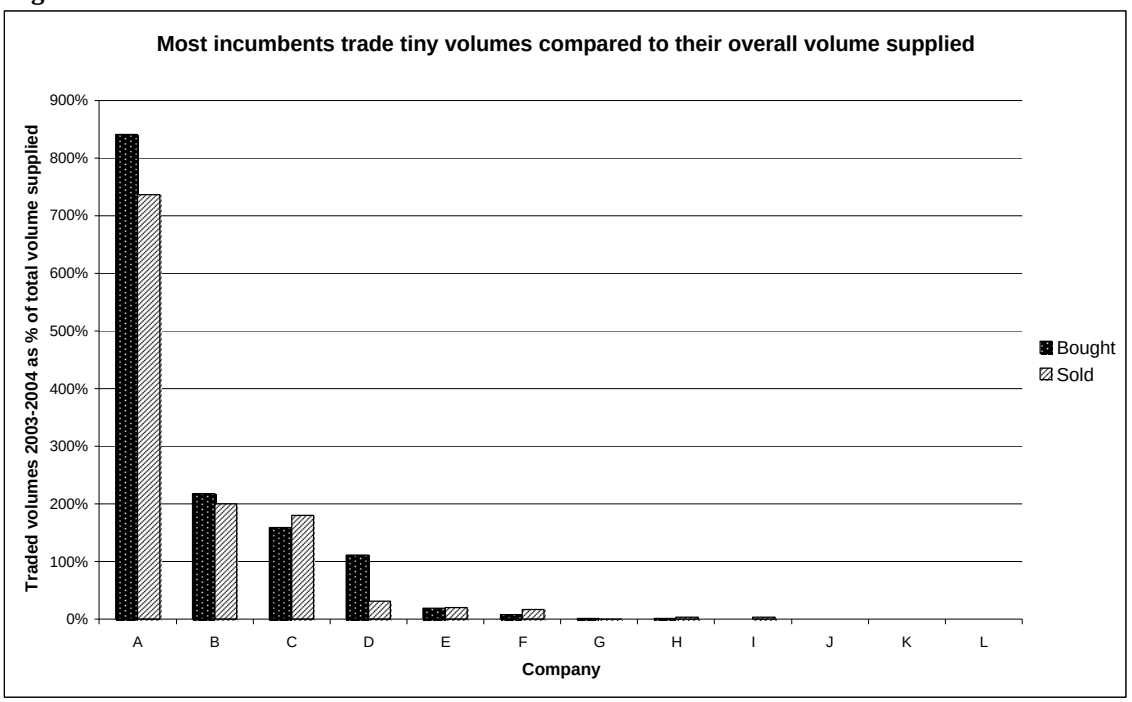


Source: Energy Sector Inquiry 2005/2006

(90) The picture is therefore that only a small number of incumbents trade actively on a significant scale. Indeed, for most incumbents trading is insignificant as a proportion of

the gas sold (see Figure 10). This graph does not show incumbents engaging in a trading pattern typical of liberalised markets, which would be likely to see trading of more than 100% of total supply[59].

Figure 10



Source: Energy Sector Inquiry 2005/2006

(91) The localised pattern of incumbent trading is also important. Only two incumbents are active across all European hubs, providing the arbitrage across geographic distance that will be necessary to create price convergence.

II.1.4. Barriers to new entry

Entry and expansion barriers

(92) In view of the continued high level of concentration on many gas markets, it is important to seek to identify the entry and expansion barriers facing new market entrants.

(93) In order for new suppliers to enter the gas market, as well as to expand existing activity, companies depend on a number of factors. Suppliers are dependent on stable access to gas, which has to be available both over a time-scale corresponding to the contractual time-scale required by customers, and at a competitive cost (including mechanisms for managing price risks).

(94) Suppliers also need to have transparent and non-discriminatory access to the transportation network on terms matching customer needs (this can include, for example, short-term capacity on the secondary market, reasonable liabilities, etc).

[59] Centrica is not included on this graph.

(95) Linked to the previous two factors, a supplier also needs access to flexibility – both as regards predictable (gas volumes varying according to the known patterns of customer needs) and unpredictable events (such as production break downs). Such access to flexibility includes, inter alia, storage, balancing and contract terms, all of which need to be accessible in a form that is appropriate for the supplier's portfolio.

(96) Downstream, the supplier obviously needs access to customers, which means that there must exist appropriate switching processes and an absence of exclusionary practices from incumbent suppliers.

(97) Overall, the supplier must be able to achieve a sufficient gap between prevailing retail prices and costs. If gas is controlled by incumbents, networks are congested, flexibility is not easily available or customers cannot easily switch supplier, market entry or expansion will be difficult.

(98) New entrants (including companies expanding their markets) in the gas sector are not a homogenous category. Since many countries/regions have in the past been dominated by a single (often monopoly) supplier, a broad definition would include all companies except the incumbents in that country/region.

(99) The entrants with least barriers to overcome should be the gas incumbents (national or regional) expanding their business into a new geographic area, since these will normally already have a portfolio (including gas, network capacity, swapping capacity, storage, etc) constituting a good starting point for expansion. Nevertheless, as shown in chapter II.3, the activity of many of the larger incumbents has been surprisingly small outside their traditional markets.

(100) Other entrants can typically include electricity companies moving into the gas sector (often bringing with them good customer relationships). Producers moving down-stream will normally have access to gas and flexibility, while (rarer) gas consumers moving up-stream would have their own demand as a stable customer base. Pure new entrants lack initial access at all levels, and therefore face greater difficulties in building a successful wholesale business.

New entrants' experiences

(101) Given the continued high level of concentration on wholesale markets, it could be expected that new entrants would express concern over all or some of the above-mentioned barriers to entry. This is indeed confirmed by many of the responses from companies that have responded to the Inquiry. The following responses mainly concern entrants with operations in Belgium, France, Germany, Italy, Netherlands and UK, since the majority of relevant responses have referred to these markets. The absence of comments for other markets should, therefore, not be interpreted as an absence of barriers to entry. It should, moreover, be noted that many small new entrants had difficulty responding to the inquiry due to resource constraints.

(102) As regards access to gas, many new entrants have replied that they source their gas from the incumbent importer or domestic producer of gas, who is also in most cases the former monopoly supplier to end customers (i.e. a competitor). The exact nature of these relationships vary: from a framework contract allowing flexible offtake to a series of precise volume contracts. The delivery timescale is typically medium-term (a few

years or shorter). Whereas the responses show that incumbents expanding into new markets, producers or large electricity companies can often manage to source at least part of their gas from producers/exporters, this is normally not the case for most other entrants.

(103) A number of responses have pointed to poorly functioning wholesale markets, resulting in difficulties obtaining access to gas. In some countries, entrants can access gas through gas release programmes, but several entrants have commented that these programmes are not adequately designed to meet their needs (for example, in Italy, comments included criticism of procedures, small programmes and high prices). Comments as to the lack of liquidity, including on hubs, were made by a number of entrants in several countries (for the UK, such comments referred to the forward market). The lack of availability of L-gas and/or conversion capacity of H-gas to L-gas was also raised by entrants in different countries.

> Quote from a new entrant: "[*Incumbent*] offers exclusive and non-exclusive agreements. The onerous terms of the non-exclusive agreements, which expose the purchaser to volume risk, and the position of [*Incumbent*] are such that, for new entrants, the only feasible option to purchase gas is by means of an exclusive agreement with [*Incumbent*], ruling out any competition with other (wholesale) suppliers of gas."

(104) Problems relating to network access are a recurring theme among new entrants. For example, regarding Belgium and the Netherlands several entrants voiced concern regarding the availability of network capacity. In Italy, many entrants were particularly concerned about the lack of import capacity. As regards Germany, concern was raised by several entrants regarding not only the availability of network capacity, but also the complex process for booking capacity. Such concern was also voiced by entrants wishing to transit their gas through Germany to other markets. Also for France, the complexity and costs of transporting gas through several zones, was raised as a problem. Comments on lack of network transparency have also been frequent.

> Quote from a new entrant: "There is no comprehensive synopsis of all networks in Germany. A system user must identify all networks they need to use for transport activity which is strenuous legwork. An overview is necessary in Germany where a transport often entails three network levels and three to four system operators."

(105) Access to flexibility has also been raised as a concern by entrants in several countries. In particular, problems in relation to access to storage, including poor transparency, have been raised as a problem by many entrants. A number of entrants, especially in Germany, also pointed to difficulties in complying with balancing rules.

(106) In relation to accessing customers, comments have included problems with metering services, with building physical connections to possible customers and with customers being contractually tied to an incumbent. The Commission is already investigating a case of alleged foreclosure due to a network of exclusive dealing agreements. There are indication that similar problems may exist in other markets.

(107) Consequently, responses confirm that companies trying to enter the market, or expand their activities, face major barriers to entry in the form of difficulties in accessing gas,

networks, flexibility and customers. Comments also point to onerous or ineffective regulations, onerous credit requirements and to a generally strong position of incumbents.

Quote from a new entrant: "There is insufficient transparency such that it is impossible to obtain a competitive supply at the burner tip by purchasing wholesale gas, transport, distribution and storage capacity discretely. The [*Incumbent*] companies have a decisive controlling interest at every level of the economic value chain."

Conclusions

Access to gas for new entrants is essential for the future development of European gas competition. There are three main sources from which gas may be sourced: imports, domestic production and wholesale trading. Gas incumbents remain dominant in their national markets by largely controlling gas imports and/or gas production. Control of imported gas is mainly exercised through long term gas purchase contracts with upstream producers. Although incumbents trade only a small proportion of their gas on Continental hubs they nevertheless dominate trading on most hubs.

There has been little new entry into the European gas markets. The overall picture for new entrants is one of dependence on incumbents for services throughout the supply chain. This includes access to gas, networks and storage. When combined with the lack of transparency, ineffective wholesale markets and in the absence of effective regulation this dependence affirms the dominant position of incumbents and is seriously impeding the development of competition.

II.2. Vertical foreclosure

(108) Vertical integration of operators active at different levels of the supply chain through common ownership or control can foreclose the availability of crucial inputs for actual or potential competitors. Long term contracts can have similar effects if they result in effective foreclosure of key inputs. Long term contracts can also foreclose access to customers.

(109) As the previous chapter showed, incumbents control most of the gas present on the national market. This dominance (which arises mainly from long-term contracts with producers) is combined with customer relationships that are also largely concentrated in the hands of the same companies. There are also significant rigidities in these markets due to structural factors such as pipeline congestion and clauses in upstream contracts. It is therefore particularly important to ensure that this concentrated and rigid market structure is not propagated to the gas markets further downstream within Member States.

(110) During the term of the agreement ex ante competition for the customer or the input concerned is excluded. The longer the duration of the contract, the greater the loss of scope for competition during its life. Furthermore, with concentrated markets, foreclosure through long term contracts is a particular concern, since in order for competition to develop, new entrants and suppliers seeking to increase their market share must have the possibility to purchase the gas they require, to gain access to network and storage capacity, and to contract with customers. Depending on market circumstances long term contracts can result in foreclosure. This is particularly the case where they lead to a good part of customers or an available input such as transport capacity being tied to a dominant player.

(111) Community legislation to open gas markets aims to ensure that access to markets is not foreclosed by lack of access to transport infrastructure. The second Gas Directive also recognizes the importance of access to other important gas infrastructure, notably storage. In gas markets not only access to infrastructure poses problems for new entrants. Incumbents also largely control the availability of gas, through their contracts with producers. Before turning to vertical foreclosure of gas infrastructure, the vertical foreclosure issues between production and supply are discussed.

II.2.1. Long-term contracts between producers and suppliers

(112) Existing import contracts cover the production from almost all existing gas fields from which gas can be transported to Europe by pipeline. “Free” gas sources that are available in the short term to entrants, and on economically viable terms are lacking[60]. In addition, wholesale gas markets in Europe are not liquid enough to provide confidence about gas availability. (The UK NPB being an exception.)

[60] Such “free” sources may develop in the future, notably as LNG develops. As regards potential new pipeline sources, new fields are being explored and developed within Europe (particularly in the North Sea), but these tend to be smaller than the main past finds and will often be controlled by the incumbent. New fields are also being developed in Russia, but these would appear likely to be marketed in the traditional way to the former incumbents or companies in which Gazprom has ownership or other links.

(113) Given the lack of "free" gas in the upstream wholesale sector and the lack of hub liquidity, it is essential to analyse the characteristics of existing import contracts. In fact several characteristics of these contracts are of prime importance in assessing entrants' possibilities to access gas.

- Upstream supply contacts are generally of long duration and are often extended in a way that does not allow for effective *ex ante* competition. In combination with other relevant factors such contracts may make it difficult for new entrants to obtain access to adequate supplies of gas. If significant volumes were re-contracted frequently then entrants would be able to bid at that time to interpose themselves as the buyer of the gas, but this is not the case[61].

- Long term supply contracts generally offer buyers a substantial degree of flexibility in terms of offtake. Incumbents can use flexible nominations under the contracts to provide flexibility. They can also, despite take-or-pay obligations, avoid buying more gas than they need, which limits their need to sell on hubs. The result is depressed hub liquidity reducing the availability of gas to new entrants.

Flexibility and risk allocation

(114) The allocation of risk in incumbents' import contracts generally follows a standard pattern. Price risk is typically borne by the producer, in the sense that the contract price is indexed to a basket of alternative fuels. These indexation practices are described in more detail in section II.5. The other main risk to be allocated through these contracts relates to volumes. The contracts stretch for many years into the future, which implies uncertainty about the buyer's future needs (i.e., how much gas will be needed, given the evolution of its own customer portfolio). As already mentioned, gas contracts typically contain flexibility provisions which enable the buyer to vary the actual take.

(115) Many of these import contracts are for very long durations. The sample of contracts reviewed includes a number of contracts dating as far back as the early 1960s. The majority of the contracts reviewed were concluded during the 1980s or 1990s, but there were also a significant number of post-liberalisation contracts. Overall, a duration of 15-20 years is typical.

(116) Many of the older contracts have been modified significantly over their lifetime. These modifications (through annexes or side-letters) relate to a number of themes: they modify the volumes to be delivered, or the price-related terms; they modify delivery points; or they clarify interpretation of the contract. In a number of cases, contracts that were initially restricted (in time, or in the volumes to be delivered) have been extended.

Flexibility in import contracts

(117) The exact nature of flexibility provisions varies greatly between import contracts, and between regions. Some contracts establish a global amount that should be taken over

[61] Moreover, the typical characteristics of the long term import contracts make it very difficult for most entrants to enter into such an agreement. The buyers in these contracts assume substantial risk that can most easily be managed by buyers with strong downstream market positions. This might be possible for certain entrants energy markets as has been illustrated e.g. in the Spanish market. However smaller entrants would need to buy gas from other sources.

the course of a contract. Many contracts establish an "annual contractual quantity", but allow the buyer to take a defined percentage less or more than this over the course of a year. Many contracts also specify monthly or daily maximum or minimum quantities. Normally, where multiple limits apply, one of the limits is deemed to over-rule, or secondary limits are calculated on the basis of the main limit.

(118) There are in addition a small number of contracts that have no contractual quantities, or where the quantities are to be nominated by the seller. These typically relate to small fields, and this mechanism might be used where the technical characteristics of the field make forecasting yield difficult.

(119) These contracts typically provide specific rules for the situation where the buyer does not take the whole of the gas required in a given year. In these circumstances, the buyer may be able to defer delivery by one or more years, or delivery obligations might be averaged over a number of years. Alternatively, the buyer might be required to pay for gas not taken.

(120) It is, however, extremely rare for suppliers to pay for gas not taken. We have analysed the purchase contracts of around 75 suppliers, and found only one clear example of such a payment being made, for a relatively small volume. We have, however, also seen a significant number of re-negotiations of contracts, involving prices as well as reduction of quantities or relaxation of limits. These re-negotiations often appear to constitute payment in exchange for not taking gas.

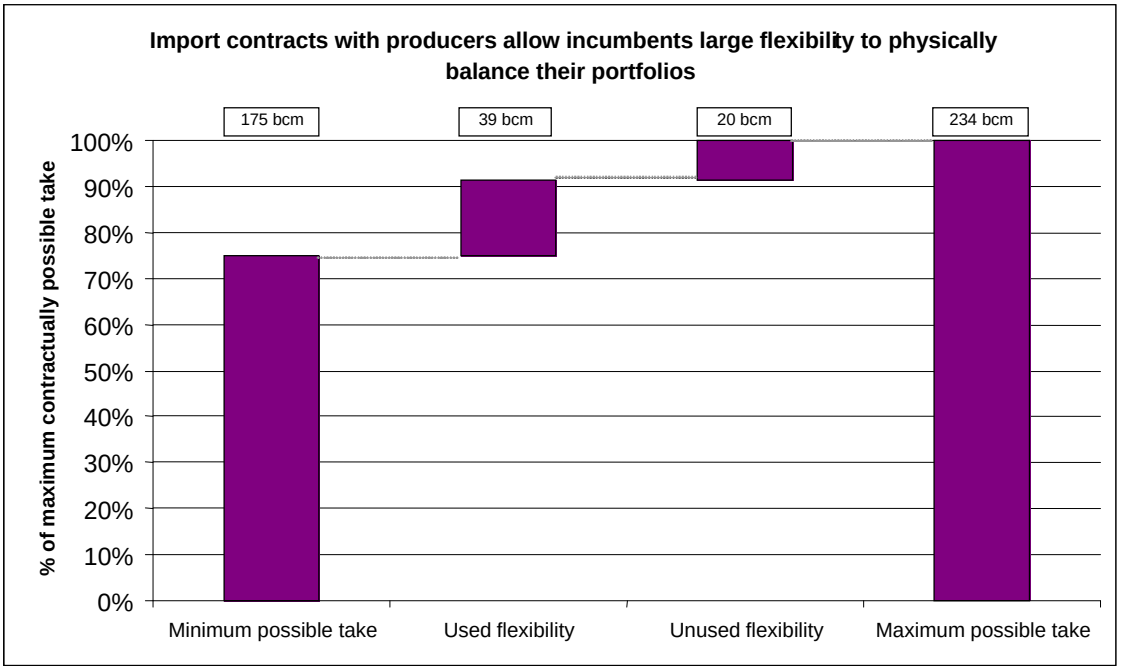
(121) For whatever reason, it does not appear to be the case that European incumbent importers are substantially over-contracted, and so we should not expect a Europe-wide "gas bubble" to emerge for this reason in the coming years.

(122) By far the most common scenario is that the flexibility inherent in long-term contracts has been sufficient, so that take-or-pay provisions have not been used. This flexibility is very large. Figure 11 shows the flexibility in our sample contracts[62], and shows that collectively these contracts offered the buyers 25% flexibility. (That is, the minimum that could have been taken in 2004 under these contracts was only 75% of the maximum total take.)

(123) As noted above, the extent of flexibility varies greatly between contracts. Figure 12 shows the degree of flexibility (the margin between minimum and maximum possible take in 2004, as a percentage of the maximum possible take) for each contract in our sample. It shows that there is a relatively small number of inflexible or highly flexible contracts, but a typical contract has 20%-40% flexibility to increase or reduce the total annual take. (Note that this is annualised flexibility, not seasonal flexibility which would typically be greater.)

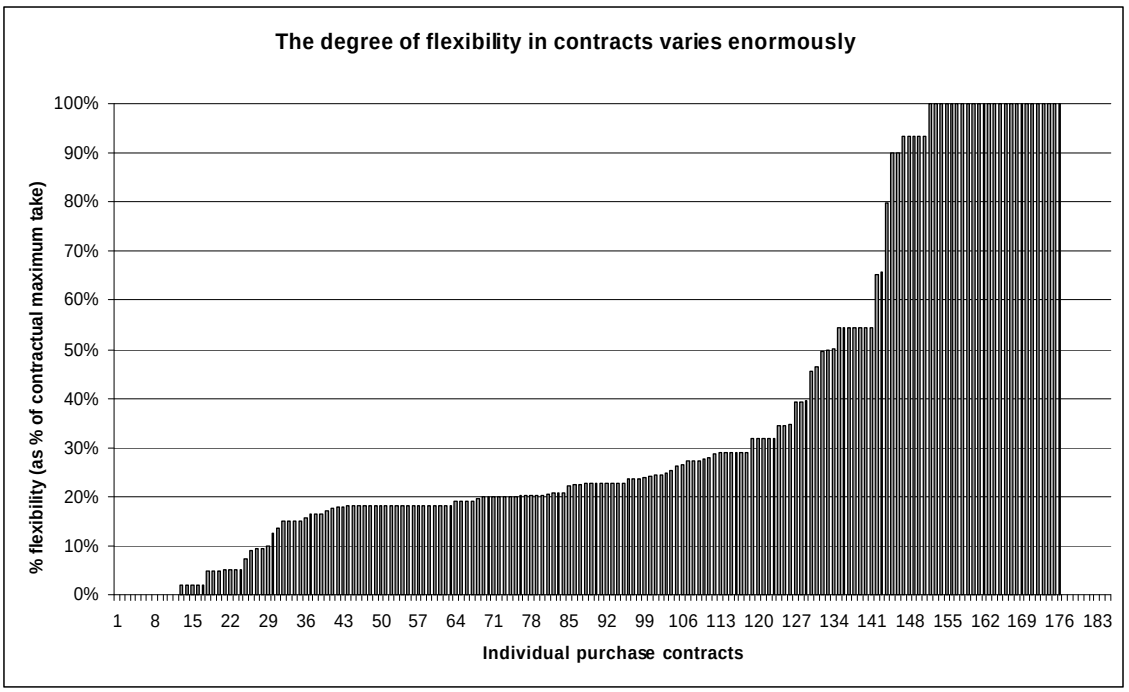
[62] Contracts were excluded from the sample where full summary data were not provided since at this preliminary stage it has not been possible to analyse in detail all contracts. In particular, contracts where data on annual and monthly maximum and minimum quantities were not provided have been excluded, since only using annual limits often suggested a contract was delivering out its contractual limits where close analysis of the contract showed this was not the case. After these exclusions the sample includes 306 contracts representing 208 bcm actual take in 2004.

Figure 11



Source: Energy Sector Inquiry 2005/2006

Figure 12

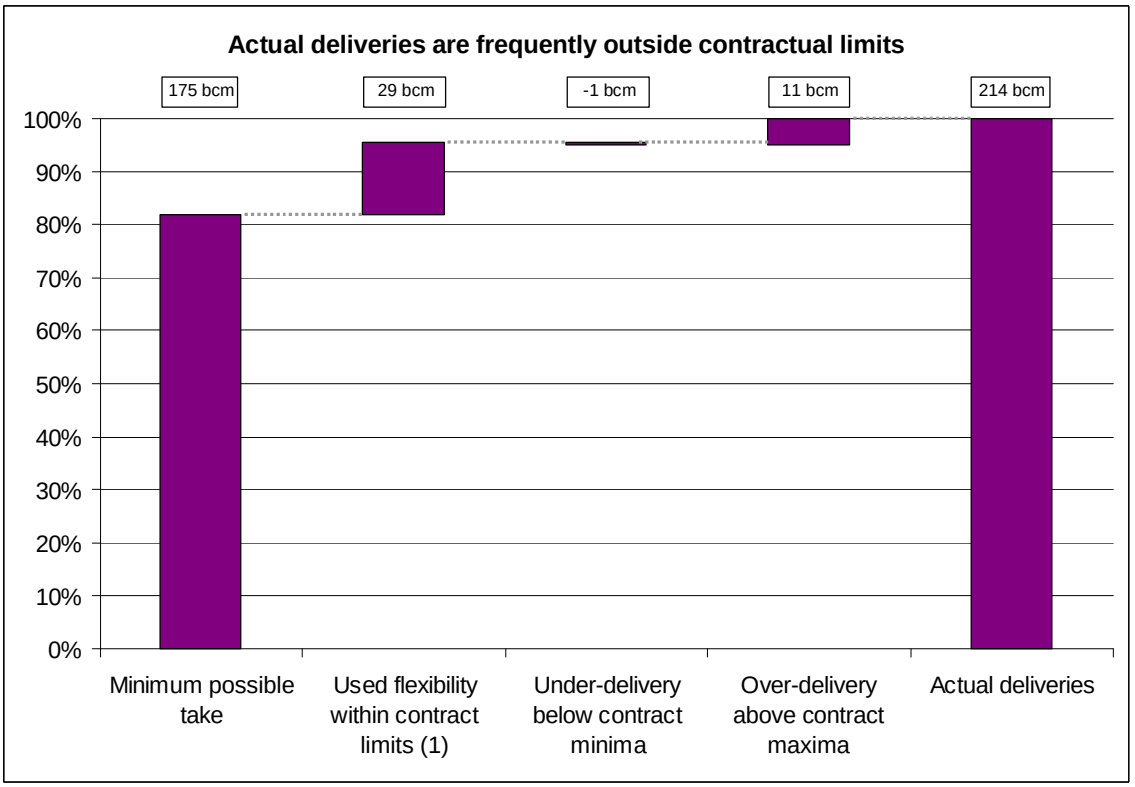


Source: Energy Sector Inquiry 2005/2006

(124) As well as the flexibility inherent in contract terms, for 11% of contracts the actual take in 2004 was in fact outside contractual limits. Figure 13 shows that the volumes of gas delivered outside contractual limits were overall relatively small, and that contracts delivering more than contracted volumes were much more important than those delivering less than contracted volumes. (In fact, only one company was taking less than contracted minima.) Nevertheless, the frequency with which producers agreed to

deliver outside contracted limits underlines the flexible and co-operative nature of these contractual relationships.

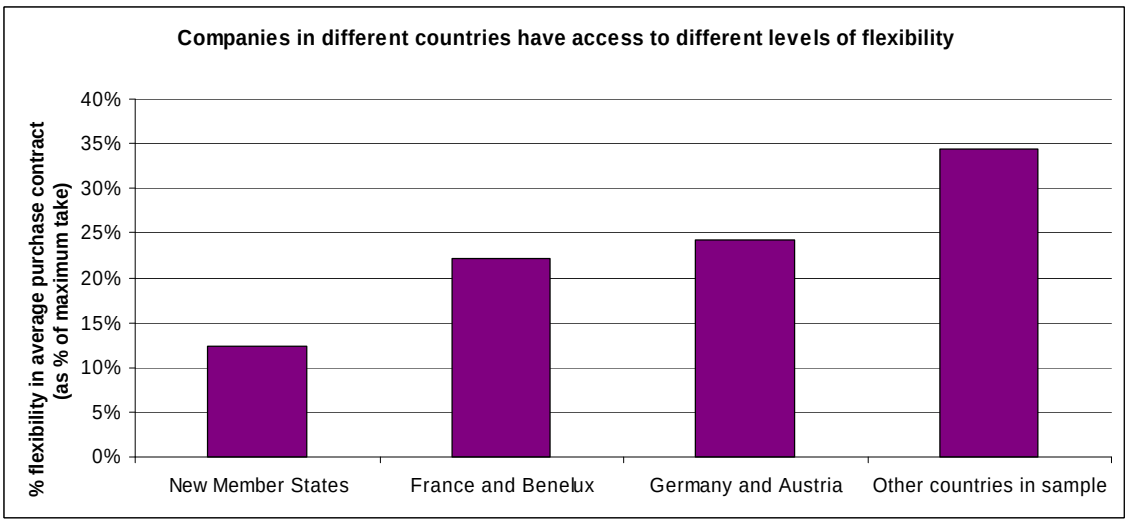
Figure 13



Source: Energy Sector Inquiry 2005/2006

(125) The average level of contractual flexibility varies between buyers importing to different countries - see Figure 14. Typically, the least flexible contracts are those under which gas is bought by incumbents in the new Member States, while the most flexible are in the "other" countries (Italy, UK, Scandinavia).

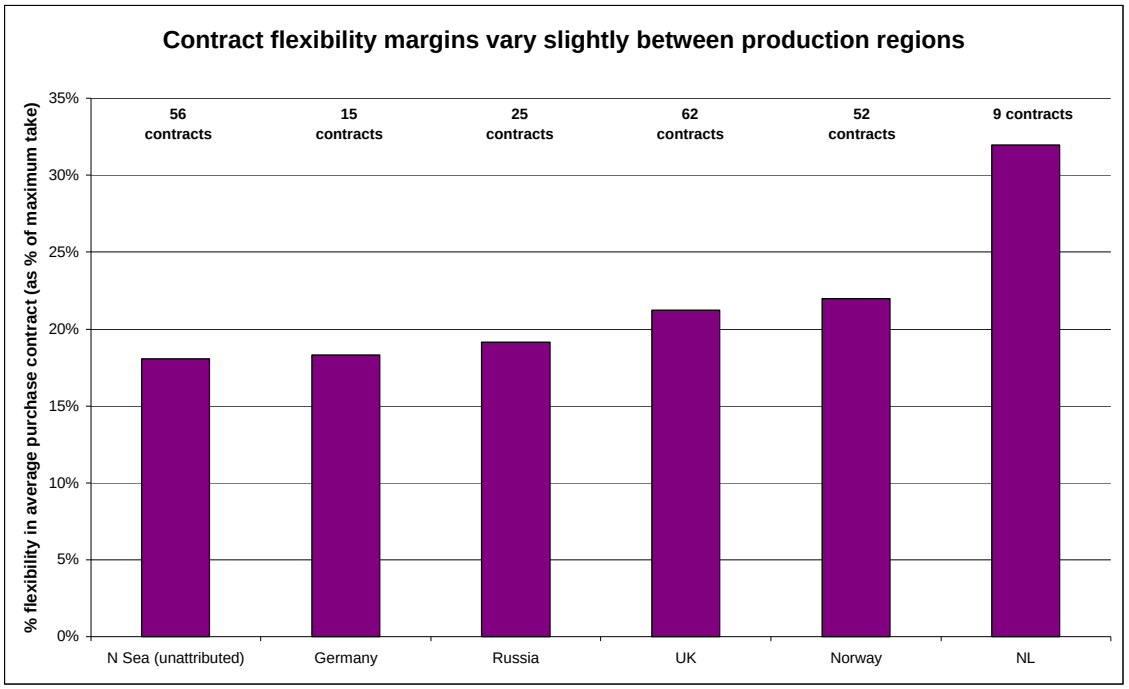
Figure 14



Source: Energy Sector Inquiry 2005/2006

(126) The average level of flexibility may also vary slightly by the region in which the gas was produced. Figure 15 suggests that flexibility levels tend to be a little lower in contracts for Russian gas than in North Sea contracts. (However, many contracts could not be allocated reliably to a particular production source and so have been omitted from this graph, or allocated to the general North Sea category. Given this weakness in the data, the apparent differences between regions are probably not large enough to be significant.) The graph also appears to show that the sample of contracts that are clearly for Dutch gas have larger flexibility margins. This may be because of the importance of the highly flexible Groeningen field.

Figure 15



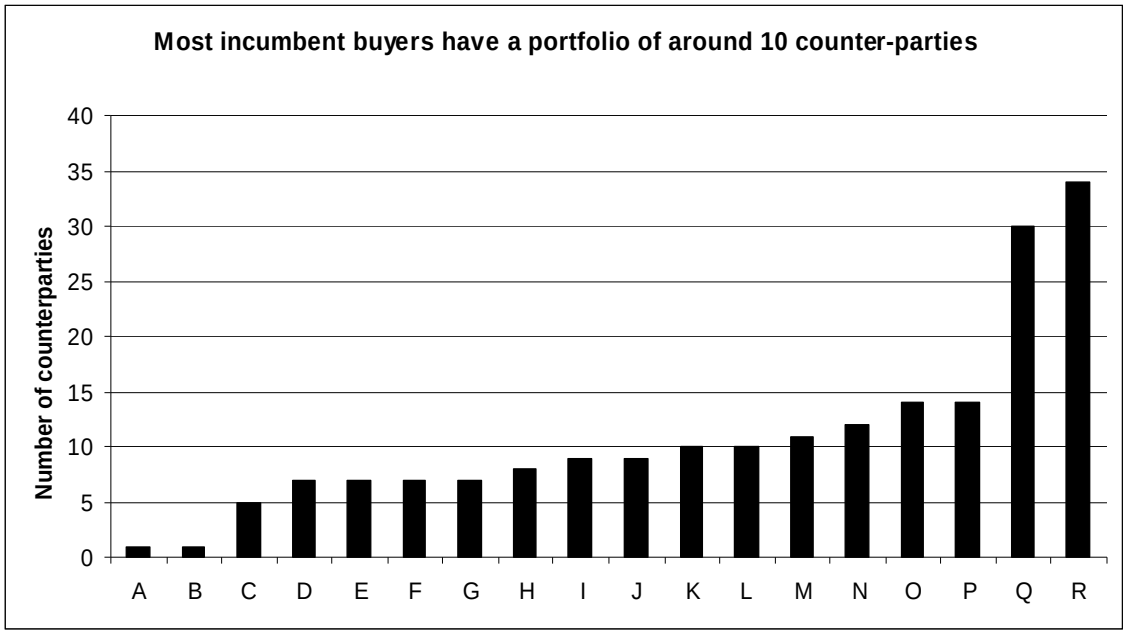
Source: Energy Sector Inquiry 2005/2006

(127) We might expect that markets with access to large local flexibility (e.g. large, flexible gas fields as in the Netherlands or substantial storage) would have less flexible supply contracts. The Dutch contracts form part of such a pattern, as noted. However, this explanations is clearly not the only one. For instance, contracts of new Member State companies tend to be markedly less flexible, although they are not in general more richly endowed with local flexibility compared to companies close to North Sea gas. Another possible explanation for varying flexibility levels is that buyers for whom liberalisation in their own markets is the most recent have not yet had time to negotiate contractual flexibility, or have not yet needed to. It could also be that buyers with fewer choices between gas producers have been less able to negotiate such flexibility.

Incumbent contract portfolios

(128) Most incumbents have historically bought gas from diverse sources. This preliminary report firstly looks at the number of counterparties in the contracts. The picture is varied between Member States.

Figure 16



Source: Energy Sector Inquiry 2005/2006
Note: Two of the companies analysed only buy through one contract. These are located in smaller new Member States which have traditionally had few purchasing options because of the physical configuration of pipelines and contractual limitations on counter-flow trading. Companies Q and R on this graph are also atypical in having a significant role in managing offshore production, and their much larger number of counterparties represents a role in aggregating production from smaller North Sea fields exploited by smaller producers.

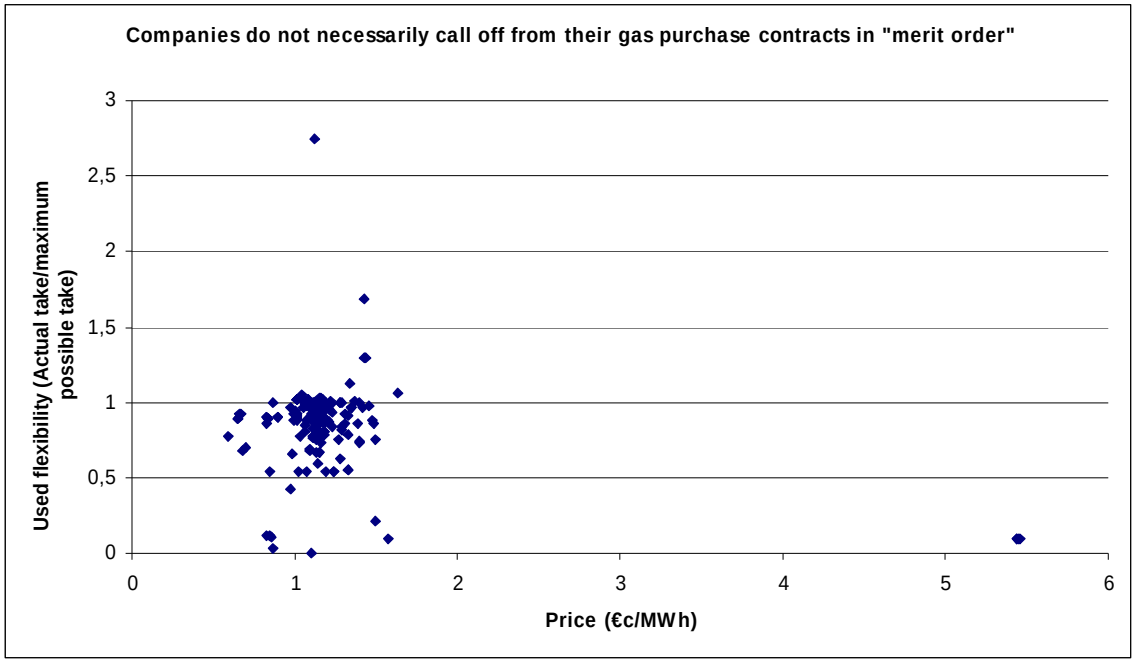
(129) As Figure 16 shows, most incumbent importers buy gas from around 10 counterparties. The frequency of portfolios of 7-15 counterparties suggests this range is adequate for risk-management purposes. Of course, not all counter-parties are of equal importance. Most incumbent importers have one or more "lead suppliers", which tend to supply 3 to 5 times more than the average supplier[63].

(130) The number of contracts tends to grow over time, as an importer will frequently sign a new contract with a producer instead of modifying an existing contract. This is far from being invariably the case, however, and in many cases side-letters are used to increase the volumes delivered under existing contracts.

(131) It might be expected that the volumes actually taken under various contracts would depend mostly on the contract price. However, across our sample of contracts the relationship between contract price and flexibility used appears quite weak.

[63] Put another way, the standard deviation in volumes taken from the various counter-parties in an incumbent's import portfolio is generally between 120%-180% of the take from the average counter-party.

Figure 17



Source: Energy Sector Inquiry 2005/2006

(132) Figure 17 above shows the scatter of contracts across the two axes which represent the 2004 average price (on the X axis) and the proportion of the contractual maximum take that was actually taken in 2004 (on the Y axis). We might expect to see on the graph a trend from top left (the cheapest contracts being 100% exploited, or even more) to bottom right (the dearest contracts being used only to fill peak demand). However, such a pattern does not appear. In fact, what is most striking is that there does not appear to be any single pattern that explains the behaviour of all incumbent suppliers[64].

(133) Consequently, it would appear that there is no "gas merit curve" under which cheaper contracts are nominated systematically before more expensive ones. Closer analysis suggests that companies that systematically nominate to exhaust the flexibility margins in cheaper contracts before moving onto more expensive ones tend to be companies that buy gas predominantly from a single production region. They are also in many cases companies buying for markets that have not yet been significantly affected by liberalisation, so that the pipeline routes for physical delivery are straightforward. In contrast, the companies least likely to nominate the cheapest gas first tend to operate in more complex situations, handling various qualities of gas, and being located towards the geographic centre of Europe where pipeline congestion may mean they are physically unable to flow gas from certain sources[65].

64 There is no linear "best fit" line that can show an overall pattern with any degree of confidence No linear best-fit line has an R-squared of more than 0.17. Even removing the outliers (below 25% and above 150%) only raises this to 0.24.

65 In addition, certain contracts reflect in the price the difficulty of using the gas. For instance, gas from one UK North Sea field, which falls out of the quality specifications for the UK market, is priced particularly cheaply since it can only be used in one power station (which has an exemption from the normal quality specifications, but incurs significant cost to use this gas). There is no reason to expect a contract of this kind to be fully nominated, even though the gas is low-priced.

Contract terms that affect competition conditions.

(134) Incumbents' purchase contracts may contain terms and conditions which prevent the development of liquid wholesale markets or otherwise prevent cross-border trade. In particular, a number of contracts relating to new Member States contain territorial restrictions that prevent buyers from re-selling the gas outside a defined area (or other terms with equivalent effect, such as various forms of profit-splitting mechanism). Such provisions were historically included in many other contracts through which companies in Western Europe bought gas, but following a series of cases opened by the Commission those investigated to data have largely been removed[66]. Some of these cases were concluded by formal decisions that territorial restrictions infringe Article 81 of the EC Treaty[67].

(135) Import contracts may also contain other terms that affect the supply of gas on the market. "Reduction clauses" have been common. These are contract terms which allow a buyer to reduce the amount of gas taken if the seller enters the buyer's market as a direct competitor. These are often taken to be the counter-part of take-or-pay clauses, since without a reduction clause the seller might notionally otherwise be paid twice in relation to the same demand: by end-user customers for retail gas it has sold them directly; and again by the counter-part in the take-or-pay contract, unable to take the wholesale gas volumes.

(136) We have also found restrictions in contracts between suppliers and end-customers. Use restrictions appear to be common, that prevent the gas being used for any other than a defined purpose. For instance, this prevents a large industrial user from reselling gas to the market should the wholesale price rise above its contract price. Such restrictions have an evident negative impact on overall market liquidity.

(137) In addition, a significant number of contract terms have come to light that require either buyer or seller to share confidential and competitively sensitive information with their counter-party, for instance when prices are reviewed.

II.2.2. Vertical integration of supply and infrastructure companies

II.2.2.1. Insufficient unbundling of networks

(138) The gas incumbents are often vertically integrated and active on several economic levels. Such a linkage between different economic activities leads to incentives for these companies to exercise preferential treatment of their own upstream or downstream branches as compared to third parties. This contributes to market foreclosure and thus hampers competition.

(139) The second Gas Directive imposes obligations on gas network operators with regard to legal and functional unbundling between transmission and distribution networks and supply functions. The companies concerned are obliged to create separate legal structures for the network and supply activities and to install separate management for each of them. Ownership unbundling is not required under the Directive. The combined

[66] Cases are still active relating to territorial restrictions in contracts covering 11% of Italian consumption and 13% of Spanish consumption.

[67] See press notice IP/04/1310 Gaz de France/ENI/ENEL

operation of transmission, LNG, storage and distribution remains possible, if the combined operator is independent in its legal form and organisation from the remaining fields of activity.

(140) Particular importance is attached to unbundling in the area of decision-making and business organisation. The day-to-day management of the network operator and all related decisions must be made independently and without interference by the parent companies. Regarding business organisation, the Directive does not contain any exact standards as to the extent that jointly used assets (such as buildings, data processing systems, personnel and finance services, car park) must be actually divided between the unbundled companies. Whenever services are shared, this must represent the most reasonable solution economically, also compared to the outsourcing of the services to third parties. The shared services are to be provided from outside the network company, for example by the holding company, and no cross-subsidies must take place.

(141) The Directive sets out minimum criteria for the independence of the operators to be unbundled. The management of the network operator – from managing director to middle management - may not take any functions in other divisions of the operator, nor receive remuneration attached to the success of the supply company. Sufficient decision making power over the capital assets necessary for business management – including network development and maintenance - has to be granted to the network operator, within limits that may be contained in financial plans approved by the parent company. The management must be able to practice this power independently and may not be given any instructions by the parent company regarding the day-to-day business. This applies to network operators which own the network, and to those which operate it on the basis of a lease, for instance.

(142) Operators have to prepare a compliance programme serving as a formal framework to prevent discriminatory behaviour and to protect the confidentiality of business information. Employees of network operators have to refrain from making any recommendations to customers regarding the choice of suppliers. The compliance programme must be implemented actively by the network operators through appropriate training, written statements of acceptance of these rules, and a clear framework of sanctions in case of violations. Network operators have to submit annual reports on the implementation of the compliance programmes to the regulatory authority, in order to facilitate their supervision.

(143) For operators of gas storage and LNG infrastructure, only accounting separation is required. Member States are authorised to relieve integrated gas operators supplying less than 100,000 customers, or small isolated networks, of the legal and organizational unbundling requirements. This is justified on the basis of the high transaction cost of unbundling and the limited potential for discrimination by small operators. The Member States are authorised to postpone the legal unbundling for all distribution networks until the complete market opening on 1 July 2007. This possibility, however, does not apply to organizational unbundling nor to transmission network operators.

(144) Incomplete legal and management unbundling can be as such contrary to the second Gas Directive and in addition lay the ground for discriminatory behaviour of vertically integrated operators in favour of their own upstream or downstream operating arm, to the detriment of new entrants. Such cases could amount to an abuse of the TSO’s dominant position under article 82 of the Treaty.

(145) In a number of Member States, the unbundling provisions are still missing due to the lack of (timely) transposition of the Second Gas Directive into national law[68]. This is currently still the case for Member States and the Commission has initiated a number of infringements proceedings as a consequence thereof.

(146) Some Member States (Denmark, the Netherlands, Sweden and the UK) have gone further than the legal obligations set out in the Second Gas Directive by introducing ownership unbundling. Other Member States are currently considering introducing ownership unbundling (Italy) or have adopted other measures restricting the ownership rights of TSOs (Belgium, Spain). Ownership unbundling appears to be the most efficient way to eliminate incentives for preferential treatment within vertically integrated operators. Notably, the UK market experience of full ownership unbundling suggest that it significantly changes the behaviour of the transport undertaking: a fully unbundled and properly regulated TSO will focus on optimising revenues from its network.

(147) Where the Member States have adopted (the required) unbundling provisions, this does not mean that all TSOs necessarily comply with them. Even if the unbundling provisions are fully implemented, there can still be incentives for preferential treatment within vertically integrated operators. In the sector inquiry, the TSOs were asked to provide information about their practical implementation of the unbundling requirements. Where this has not yet been fully completed, the process is under way. The TSOs' replies in the sector inquiry point at a number of admitted shortcomings in the unbundling process. In a number of cases, the top management of the supply company has access to strategic business information of the transport company, either directly or as a result of their representation in the Supervisory or Administrative Board of the latter. Certain investment decisions on network extensions of the transport company have to be approved by an investment committee of the parent TSO. This not only limits the transport companies' freedom, but also gives the suppliers affiliated strategic insight into developments that are highly important for their own business. Such links between the supply and the transport companies appear to be in contradiction to the provisions on management unbundling.

(148) In many gas companies, trading names, brands and logos are admittedly still shared between the transport and supply companies. Some of the TSOs concerned point out that a separation of those intellectual property assets is currently under way. Several TSOs' replies indicate that supply and transport companies still share physical assets such as office buildings and IT systems. Again, some of them highlight that separation of those assets is under preparation, with the construction of new premises or division of existing ones, or by setting up "Chinese Walls" in the IT systems. As long as a complete separation of assets is not achieved, the supply and transport companies remain visible in the markets as a joint entity which strengthens their competitive position compared to independent operators. In addition, the shared use of assets facilitates access to each others' business information which in an unbundled company is kept strictly separate.

(149) A number of TSOs' replies indicate that the unbundling requirements have not been entirely implemented with regard to the management of gas capacities. Certain TSOs do not use separate contracts for gas supplies and gas transports, but continue to subject

[68] Five Member States benefit from derogations under the provisions of the Second Gas Directive or do not have a functioning gas market.

both activities to a similar contract, although under the unbundling provisions they have to be kept strictly separate from each other. In a few cases, the network companies even transport gas for affiliated suppliers without proper transmission contracts[69]. This means that the transport and supply companies, even if they are legally unbundled from each other, continue to be and act as a single vertically integrated operator. Contractual conditions for any gas transport through the networks, be it by a sister company within the same group or by an independent third party, must be set out in a separate contract in an objective and transparent manner, so as to prevent any discrimination.

(150) The nomination of gas transport capacities does not always follow the same standard procedure for all shippers. While the supply company of vertically integrated operators can nominate their capacities directly to the network's dispatching centre, third parties with short term interruptible contracts still have to nominate their capacities in advance to the TSO who aggregates them before sending them to the dispatching centre for execution.

(151) Allegations have been made in a number of shippers' replies to the questionnaires that network operators offer preferential treatment to their supply companies and that this leads to discrimination to competitors' detriment, which gives rise to market entry barriers. This concerns a number of different aspects of network access and occurs in various Member States.

(152) A number of shippers allege that network operators continue to offer preferential treatment to their "associated" supply companies with regard to the access to available firm capacities on transit routes, notably in Austria, Belgium and Germany. This takes place either through straightforward refusals of capacity reservation requests, or indirectly through considerable price increases where are for a limited quantity reservations or stricter terms and conditions in the balancing regimes. This means in practice that independent shippers often run the risk of having to pay higher penalty charges for imbalances.

(153) This is allegedly due to the fact that many incumbents still benefit from an aggregated management of their load within the network, with capacity rights historically used by the incumbents being perpetuated into the new system. One of the most clear-cut examples of alleged discrimination described in the context of the sector inquiry concerns the fact that one of the German gas incumbents was recently able to offer a gas delivery contract for a new power plant requiring a substantial import capacity, to be shipped through the network of its "associated" network company. At the same time new entrants were not granted firm capacity on an almost identical pipeline path, although the capacities they requested were substantially lower than the ones granted to the power plant. Another example from a different Member State is related to the fact that the vast majority of primary capacity on a transit pipeline is sold to the shareholders of that pipeline.

(154) Another alleged form of discriminatory treatment is the requirement for independent shippers to offer a bank guarantee or a bank deposit for an amount equivalent to several monthly invoices before receiving access to capacity reservations. In addition, several respondents complain about the lack of liquidity and transparency on the secondary

[69] See in this respect the category identified as "without contract" in section B.II.3.3 and footnote 106 below and more particularly with respect to the East-West transit axis.

market, which make commercially meaningful capacity reservations very difficult[70]. The reported lack of transparency for gas transports on transmission pipelines concerns reserved and available capacities over the length of existing long-term reservations, the announcement and publication of bottlenecks, physical congestion of interconnectors as well as details about transport interruptions. These data, when being made available to shippers within the same group, can provide them with important competitive advantages over independent shippers.

(155) Various shippers allege that network operators offer their supply companies preferential treatment with regard to nominations management, due to a lack of harmonisation of the nominations procedure, and the high cost for independent shippers to use the TSOs' nominations management systems. Furthermore, the access to transit capacities is in some cases made conditional upon the existence of purchase or supply contracts, so that planning ahead becomes difficult for smaller independent shippers. A concrete example that was pointed out in the context of the sector inquiry is that gas incumbents do not offer new entrants wheeling services, enabling them to redirect gas flows of purchased capacities once put into the pipeline system.

(156) On the basis of their experience when dealing with vertically integrated gas incumbents in the context of imperfect unbundling and the difficulties faced in the areas mentioned above, numerous respondents claim that only full ownership unbundling will provide market-based network access and enable them to make efficient use of the mechanisms put in place in order to achieve competitive liberalised gas markets. The various allegations referred to above will be further analysed in the next phase of the inquiry.

II.2.3. Access to storage

(157) Storage capacities differ widely across Europe, due to varying geological conditions and historic investments. Owing to large storage capacity, the ratio of storage capacity to consumption is particularly high in France, Germany and Italy. There is no gas storage in Estonia, Finland, Greece, Ireland, Lithuania, Luxemburg, Portugal, Slovenia and Sweden.

(158) There are different kinds of storage facilities. Gas can be stored in salt caverns, depleted fields onshore and offshore, aquifer storage and in the form of LNG. Storage facilities have their own characteristics related to the geology and the investments which have been made. In general, inflows and outflow are more rapid in salt caverns than in depleted fields and aquifer storage. The former are therefore used for peak demand and the latter for seasonal swing. LNG storage is used as peak shaving plant.

(159) Storage for seasonal swing is filled up in summer, so that it can provide gas during the winter season and during very cold days: for the first requirement, there is a need of storage in terms of volume available and for the second, storage needs to have enough pressure to allow for a quick withdrawal. In addition, short term services (less than one year) are being developed in a number of Member States.

[70] The application as from 1st July 2006 of Regulation (EC) No 1775/2006 of the European Parliament and the Council on conditions for access to the natural gas transmission networks might contribute to improvements in this respect.

(160) It is therefore clean that storage facilities have a dual aspect. They contribute to security of supply and as storage facilities also provide an important flexibility tool, they play a crucial role for the development of competition in Europe. Storage facilities are, however, largely controlled by the historical incumbents. Regulated access to storage facilities is only provided in Belgium, Italy and Spain. In the Czech Republic, United Kingdom, Hungary, Latvia and Poland, access is partially regulated. In Austria, Denmark, France, Germany and the Netherlands access is negotiated.

(161) It was decided, in the first phase of the gas sector inquiry, to focus on issues in storage complementing the work realised by the European Regulators Group for Electricity and Gas (ERGEG) for the countries under review (Austria, Belgium, the Czech Republic, France, Germany, Hungary, the Netherlands, Poland and Slovakia).

(162) Whilst effective third party access to storage is of central importance[71], there is no legal obligation, under the second Gas Directive, to provide regulated access. Newcomers complain about a number of weaknesses in negotiated access: lack of transparency on storage use, inadequacy of storage services to their needs, lack of secondary markets, and high prices.

Guidelines on GGPSSO and the gas sector inquiry

(163) Non-binding guidelines on access to storage (Guidelines for Good TPA Practices for Storage System Operators - GGPSSO) have been developed in close cooperation by the Commission and the energy regulators and accepted by the industry in the context of the Madrid gas forum[72]. Regulators have recently investigated compliance with these guidelines and a report has been published in December 2005. Three main findings of this regulators' report can be underlined:

- On confidentiality requirements, the report states that it is important that effective market arrangements are put in place to ensure equal market conditions in particular where there is vertical integration. These arrangements apply to the quasi-totality of storage system operators are they are part of vertically integrated companies. These are: separate databases for storage operations, implementation of a code of conduct/compliance program for staff working in the storage business, effective monitoring of firewalls between the storage operator and the supply branch of the company, cost effective solutions to ensure that the storage operator and the supply business are not located in the same place. However, in the majority of cases, these arrangements are not monitored at national level and for more than 60% of storage capacity under review, compliance with the guidelines is unclear;
- On transparency requirements, the report states that publication of relevant data is crucial to the efficient and transparent operation of the storage market. However, there is very limited transparency on operational storage data in Europe, in particular about use of storage capacity. In addition, the main commercial conditions are sometimes not published although the requirement to provide these is in the Gas Directive;

[71] Other forms of flexibility also exist, but storage users have indicated that in many cases there is little or no alternative to storage.

[72] See: http://www.europa.eu.int/comm/energy/gas/madrid/doc-9/d2_EGREG.pdf

- The development of secondary markets of storage capacities is still limited and this further reduces the use of storage capacity.

Protocols

(164) When a supply branch of a company is not legally unbundled from the storage branch, a protocol needs to be signed between both entities to set terms and conditions for the use of the storage and ensure that these terms and conditions do not discriminate against other users. The gas sector inquiry has found that for four of the reviewed storage operators, it is not clear whether these protocols do exist.

Capacity excluded from TPA

(165) The second Gas Directive allows the exclusion from TPA of "the portion used for production operations; and […] facilities reserved exclusively for transmission system operators in carrying out their functions". In the Netherlands capacity is allocated to production operations[73], whilst in Poland, all capacity is booked for production operations and for TSO needs. Capacity of some other storage facilities is also excluded from TPA for these reasons. Due to the fact that storage capacity excluded from TPA may be large in some cases, it is important that this procedure is monitored by National Energy Regulators[74].

Available storage capacity, long term booking and contractual congestion management

(166) The gas sector inquiry has found that, across the countries reviewed, available storage capacity (that part of storage which is not excluded from TPA and which is not booked) is very scarce or non-existent. Out of about 25 storage operators analyzed whose storages are open to TPA only five of them indicated that they have available capacity. According to the sample, in four countries there is no available capacity at all. In another one, available capacity is very small compared to total capacity.

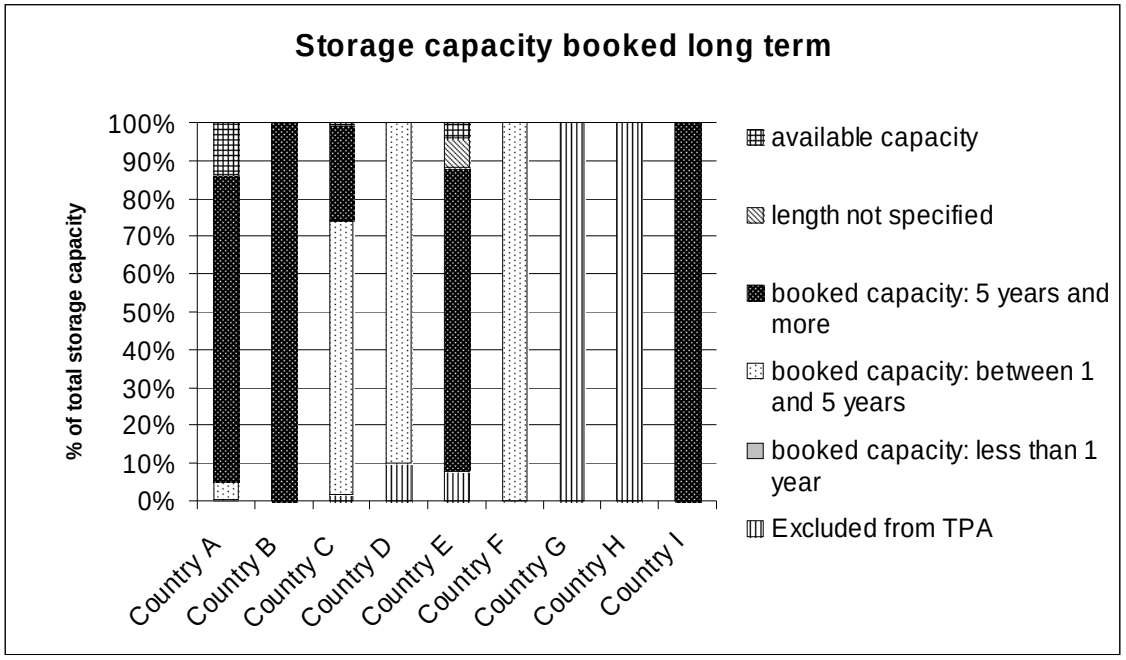
(167) Figure 18 below indicates that in two countries under review all storage capacity is booked long term and that long term contracts prevail in two countries. These contracts will expire only very slowly. In Germany, capacity booked for more than 5 years (and in some cases for 15 years) represents around 80% of the technical capacity reviewed[75]. Eight storage operators, whose joint storage capacity amounts to around 15 bcm indicated that their storage is fully or nearly fully booked long term. In addition, apart from one exception, storage operators were not offering capacity under contracts lasting less than one year.

[73] Some capacity is however made available to third parties on the primary market.

[74] These issues are considered in the DG Energy and Transport Note on Third Party Access to Storage Facilities (see: www.europa.eu.int/comm/energy/electricity/legislation/doc/notes_for_implementation_2004 (gas_storage_en.pdf)

[75] More than 80% of German storage capacity has been analysed to arrive at this figure.

Figure 18



Source: Energy Sector Inquiry 2005/2006

(168) When capacity is fully booked, and in particular for the long term, it is important that appropriate congestion management procedures are put in place to allow access to newcomers. For instance, in France, the "storage capacity follows the customer": when a supplier loses customers, it also loses storage capacity linked to the customer. Where these congestion management procedures exist, it remains to be assessed whether they are efficient, provide for non-discriminatory access to storage and meet users' needs.

Storage use, physical congestion and use-it-or lose it provisions

(169) As a general rule, storage is filled at the maximum of its booked capacity in September and October, at the beginning of the winter season. The gas sector inquiry has found that most of the storage from the sample which is fully booked has been more than 95% full at the beginning of the winter (in the period from January 2003 to mid-2005). In some cases, however, the use has been less than 90%: this indicates that there may be some overbooking and/or that some use-it-or-lose it provisions should be implemented.

Investments

(170) Investments are important due to the general high level of storage utilization rate and continuing increase in gas demand. Around 70% of the storage companies under review have planned investments in new storage capacity. Total declared investments extend up to 2015 and amount to around 20% of the capacity under review, i.e. an average annual increase of about 1.8%. This rate is lower than the general forecasts on gas demand. However, this increase is a minimum, as some companies have not indicated the amount of capacity they plan to develop and as others have also indicated that they are considering or may consider further investments. Less than 10% of the increase in capacity is made by newcomers alone; some other capacity is developed together with incumbent storage companies.

(171) In one country under review there is no planned investment; in another the increase in capacity is very small compared with the existing one. However, at this stage of the analysis it is difficult to indicate whether there is a risk of future regional shortage in storage capacity. In some cases, storage companies have mentioned a lack of geological opportunities to develop new storage sites.

Conclusions

Vertical integration of operators active at different levels of the supply chain and long-term supply agreements seem to foreclose the availability of crucial inputs for actual or potential competition:

Vertical Foreclosure

Considering the highly concentrated upstream markets, it is particularly important to avoid that these structures propagate into market foreclosure downstream.

Access to gas

New entrants can procure gas either directly from producers, or on national wholesale markets. Incumbents have long-term import contracts in place with producers, which cover the production of almost all existing gas fields from which gas can be transported to Europe by pipeline. New entrants are therefore largely foreclosed from procuring gas directly from the producers. At the same time, most national wholesale markets are not liquid enough to provide confidence about gas availability or that hub prices reflect the underlying supply/demand dynamic. This lack of liquidity is aggravated by flexibility clauses in the incumbents' long-term supply contracts which avoid situations of excess or shortage of gas, thereby reducing the incumbents' need to trade gas at national wholesale markets.

Access to storage

Access to storage is seriously foreclosed by long-term reservations. In some cases booked storage is not being fully used. Moreover, separation of suppliers from affiliated storage operators is unclear, leading to concerns about non-discrimination.

Insufficient unbundling of networks

Legal and organisational unbundling as foreseen by the Second Gas Directive is not yet fully implemented and incumbent suppliers still have access to network information through representation on the Supervisory or Administrative Board of vertically integrated companies. Suppliers and networks often share names/logos, buildings and IT systems. A number of allegations of discrimination by network operators in favour of affiliates have been received.

II.3. Market integration

(172) Competitive pressure in national markets can come from cross-border supply, to the extent infrastructure connecting national markets allows such competition to develop. In some markets significant cross-border infrastructure exists in the form of pipelines that have been constructed to import gas from producers outside the EU. In fact, gas has been transported across Europe for many decades. This "gas in transit" could compete in the respective markets provided that there are no contractual or other obstacles preventing this gas entering the markets. Access to networks connecting national markets (hereafter referred to as 'transit networks' or 'transit pipelines'[76]) is a vital prerequisite for both security of supply and competition. Indeed, cross-border sales and gas imports both from within the EU and from outside are crucial to allow gas to flow efficiently and in a reactive manner to the areas of greatest demand. Such demand tends to be reflected in higher prices on traded markets, to the extent liquid traded markets exist. Since no further major EU gas finds are expected[77], imports from non-EU countries are likely to gain in importance and, correspondingly, the significance of having an effective regime for access to transit networks will increase.

(173) The importance of pipelines connecting national markets for market integration has motivated a thorough analysis of the capacity situation on these networks. In addition, the inquiry has analysed "swaps" of gas in different locations as such swaps can provide an alternative to physical transport of gas. Before turning to these issues the extent of cross-border sales is highlighted.

II.3.1. Incumbents' sales in other markets

(174) The remaining concentration of the historical incumbents in their domestic markets is mirrored by their lack of sales in other markets. The inquiry confirms that gas incumbents engage in little cross-border trade. Certain historic incumbents have significant sales outside their home market (up to 30%). However, their effect on retail competition in the market is limited, given that the sales are often through affiliates with historic monopolies, or to linked companies in which they have participations, or are short-term trading. Although incumbents in countries with more active competition at home have sought to be more active in entering other markets (Centrica, Eni), most incumbents are active in only one or two markets beyond their historic home market. Figure 19 describes the amount of sales abroad realised by a number of incumbents in Europe.

(175) In markets with a multi-tier structure, some former regional or local monopolists have tried to enter regions beyond their historic base (this has been the case in the UK and Italy[78]). However, many local companies (e.g., German Stadtwerke) comment that they have declined to make offers to customers located away from their historic area or its immediate vicinity.

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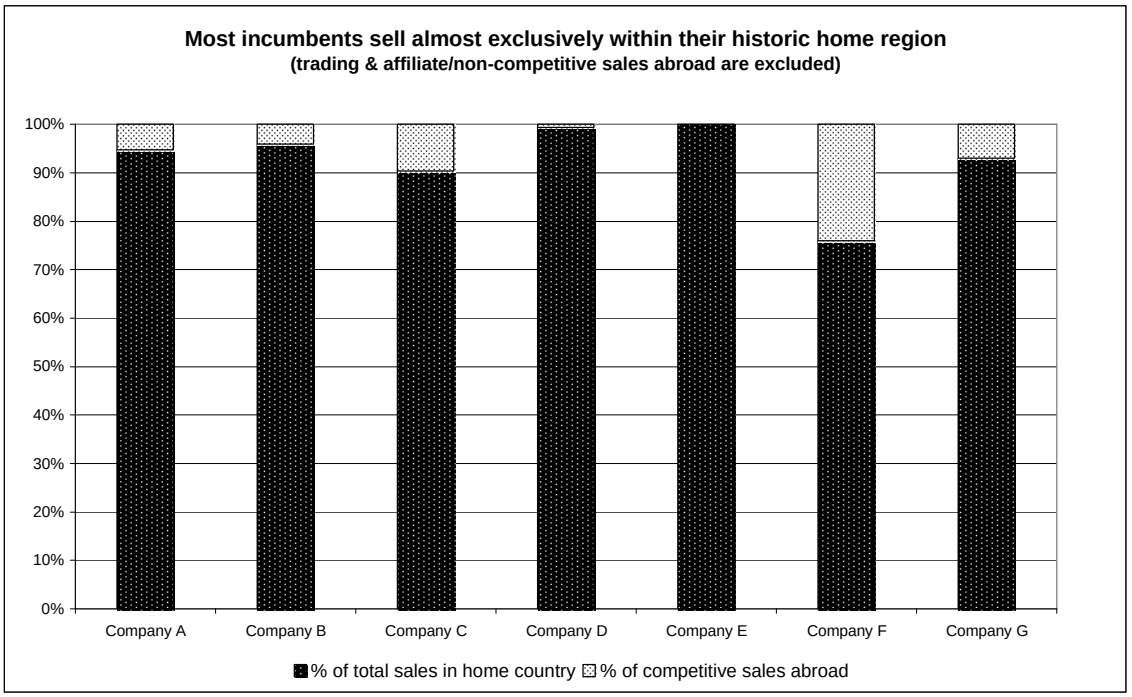
[76] The term 'transit pipeline' should be considered by the reader to refer also to any entry/exit points that form part of a transit route.

[77] See section B.I.1 "Main market features".

[78] In Italy Eni is subject to an antitrust cap so it is obliged to be more active in other markets.

Figure 19



Source: Energy Sector Inquiry 2005/2006

II.3.2. Gas swaps

(176) Analysis of the extent and nature of gas swaps offers useful insights into the functioning of the European gas market. In general, swaps appear to optimise the use of infrastructure; but they are diverse as regards their motivation, the volume of gas involved, their location, the pricing mechanism and the length of contract.

(177) Our findings suggest that gas swaps (in which two parties agree to exchange gas at one location for gas at another location or quantities of gas over time) are not a marginal phenomenon[79]. The respondents to the questionnaire swapped at least 27 bcm in 2004. These swaps amount to just over 5% of the gas volume supplied in the EU, and they could play an important role in optimising use of the transport system. Even if more transport capacity was to be available, swaps would nevertheless take place, as one party might already have gas available where the other party needs it, therefore avoiding transport risks and costs. Swaps eliminate the risk of something going wrong along the transit route, since with a swap the gas is generally already where the parties want it.

(178) Respondents to the Inquiry have identified various types[80] of swaps, depending on the reason for the swap. Geographic (point-to-point location) swaps aim to overcome some form of transport obstacle (avoidance of transit charges, of network congestion or of physical constraints of the gas network such as a pipe only flowing in one direction), while temporal swaps are used for volume adjustment purposes and often involve only smaller quantities[81]. Special types of temporal swaps taking place over a short period of

79 The swaps analysis covers undertakings from member states including Austria, Belgium, Czech Republic, France, Germany, Hungary, Italy, Slovenia, the UK and Norway. Undertakings may swap gas with undertakings from outside the EU and where these have been reported they are included in the analysis.

80 It appears that different companies have different names for the various types of swaps; this is a general overview.

81 Swaps might also be used to deal with gas quality problems. This aspect has not yet been analysed.

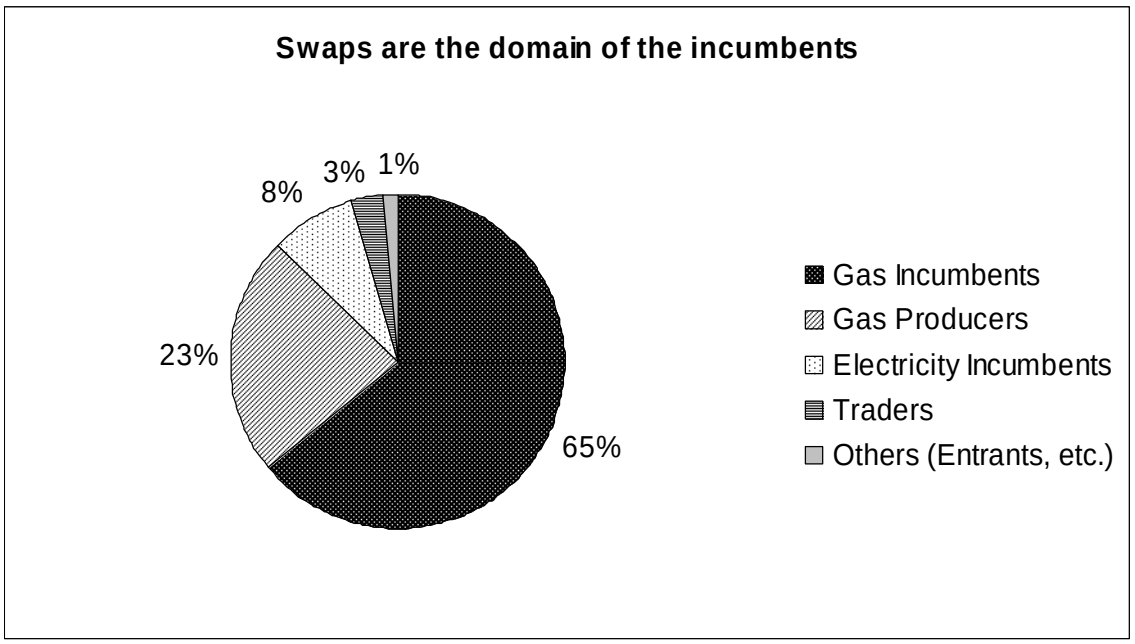
time are virtual swaps, mainly related to substituting storage. There exist also complex swaps combining the two functionalities of location and time.

(179) The price of swaps will be zero if the value of the gas exchanged by the parties is perceived to be equal, or alternatively some function of the relative difference in prices between the two locations. Explicit prices for swaps can evolve. A party may pay a fee if it has a stronger incentive than the other to engage in the swap or if the terms and conditions of the two legs of the swap are not set equally. For instance, fees can arise from differing flexibility arrangements requested by one of the parties.

(180) The duration of swaps can range from single-day swaps aiming to secure liquidity or to serve balancing purposes to several years-long framework contracts. In terms of their numbers the three largest groups are one- or two-days swaps, one-month swaps and half-year swaps, in that order. Only around 10% of the swaps examined have a duration of one year or longer, but these make up the largest part of the volume swapped in the period examined.

(181) In terms of the volume of gas involved, the largest categories are: swaps over network points in Germany; LNG swaps; intra-hub swaps; swaps from upstream points into hubs; and cross border swaps from network points to hub. Hub-to-hub swapping is quite minor in volume. Germany is the only country where there is a significant volume of gas being swapped between network points within one country.

Figure 20



Source: Energy Sector Inquiry 2005/2006

(182) Figure 20 shows that the great majority of swaps tend to be between large incumbent gas companies. There are also a significant number of gas producers and electricity incumbents engaging in gas swaps. Traders and market entrants only have a minor share of the volumes of the deals executed. Given the coincidence of circumstances necessary

for swaps to take place[82], and that gas incumbents have most of the gas, it is unsurprising that swaps tend to be the domain of the incumbents.

II.3.3. Access to transit pipelines

Congestion management

(183) In the early 1990s, EU legislation aimed to facilitate the transit of gas within the EU without touching, however, the supply monopoly rights within Member States. With the adoption of the first and second Gas Directives, as well as the Regulation on conditions for access to the natural gas transmission networks[83], it was expected that access conditions for national transport[84] and transit[85] would converge and that new entrants would be able to compete on an equal footing with incumbents for access to cross-border transit capacity. In several countries, however (including Austria, Belgium, the Czech Republic, Germany, and Slovakia), different conditions persist for gas transit and transportation. This situation is caused by both commercial and regulatory factors. The effect is that regulated third party access conditions as implemented by the regulators do not apply (fully) to transit pipelines or transit contracts[86].

(184) Since new gas sources to feed competition on national wholesale markets will originate mainly from imported gas, and new entrants face difficulties in securing primary transit capacity[87] on the same basis as incumbents, the effective management of congestion is crucial in order to facilitate competition.

(185) Congestion occurs in two forms: contractual congestion[88] and physical congestion[89]. Contractual congestion arises in instances where all the available primary capacity on a pipeline has been sold. These sales may extend over a long period (in some instances capacity sales through long-term contracts can extend over a number of decades) and there might be no effective mechanism for interested shippers to obtain secondary capacity. Contractual congestion effectively occurs at the instant that interested shippers request capacity but are refused access on the basis that all capacity is already reserved.

(186) In an efficient market, where TSO's commercial interests are not aligned with any single supply affiliate, the existence of contractual congestion should lead the TSO to employ effective congestion management measures such as use-it-or-lose-it (or UIOLI) to release contracted but unused capacity to the market. Indeed, Article 5 of the Gas Regulation obliges TSOs to maximise the commercially available capacity. The obligations to provide non-discriminatory access to networks are based on principles underpinning the "essential facilities doctrine" in competition law. This doctrine

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82 A swap will occur if party A has gas in location 1 that party B wants AND party B has gas in location 2 that party A wants.

83 It is yet too soon to analyse the effects of Gas Regulation, which will only come into force on 1 July 2006.

84 Transport directly to customers located within that country.

85 Transport across a country, without access to customers located within that country.

86 It should be noted that this is despite the fact hat the EU Directives and Regulation specify a single set of rules for access to both national transport and transit.

87 Primary transit capacity is capacity bought directly from the relevant TSO.

88 Defined in the Gas Regulation as "…a situation where the level of firm capacity demand exceeds the technical capacity".

89 Defined in the Gas Regulation as "…a situation where the level of demand for actual deliveries exceeds the technical capacity at some point in time".

provides that, under a number of conditions, companies having control of an 'essential facility' may be obliged to offer available capacity to interested third parties[90].

(187) TSOs and special capacity holders[91] in their responses to the Gas Sector Inquiry claim either that the UIOLI principle does not apply to transit pipelines at all, or at least that it cannot be applied effectively to transit. A number of the TSOs operating the pipelines, and special capacity holders controlling the capacity on the pipelines, insisted that the transit contracts signed before liberalisation cannot be touched[92]. They claim that the so-called 'ship-or pay' transport contracts, traditionally used to transport the gas bought under 'take-or-pay' import contracts, allow the historic capacity holder to re-nominate typically until two hours before the relevant gas flows are to commence. Thus, capacity not used by such historic players could be released on the secondary market only on a very short term and interruptible basis, giving potential users of the unused capacity little leeway to secure gas[93].

(188) In order to gauge the existence of contractual congestion, the questionnaires sent out in the context of the Gas Sector Inquiry included questions to TSOs, shippers and potential shippers about congestion and congestion management (including information on access refusals[94]). On the basis of these responses it has become clear that contractual congestion is occurring on a number of pipelines (and in some cases is quite severe) and yet there are often no mechanisms in place to manage this congestion.

(189) Physical congestion arises in instances where a transit pipeline is fully utilised (that is, where gas flows on the pipeline are close to, or at, the maximum flows possible) and therefore no further flows can be accommodated. In such cases it is clear that the demand for transit services is high. In an efficient market, such physical congestion should signal to the TSO[95] a need for additional capacity.

(190) It is clear that the TSO's willingness to respond to such signals is crucial in order to facilitate effective competition in the internal market for gas[96]. Further, in an efficient market, TSOs would be proactive in seeking out and responding to such investment signals in a timely manner. According to the findings of the Gas Sector Inquiry, it is not clear that TSOs have in place, as a matter of course, systems to facilitate this activity.

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90 See Judgment of the ECJ of 26/11/1998, C-7/97, Bronner, ECR, p. I-7791.

91 Where a company other than the TSO (although it can be a shipper affiliate of the TSO) has secured rights over a substantial amount of transit capacity on the relevant transit pipeline (in some cases this amount can cover the entire capacity of a pipeline), this company effectively takes on, in part, the function of a TSO in that it is primarily responsible for making available capacity to the market. Such a company is referred to as a 'special capacity holder' or 'SCH'.

92 This argumentation is largely based on article 32 of the second Gas Directive which provides for a (transitional) derogatory regime for pre-liberalisation transit contracts fulfilling minimal conditions.

93 The Gas Regulation does not enter into force until 1 July 2006 and therefore it is unclear at this time what impact the Regulation will have on this issue. In the case of existing transit contracts, the Gas Regulation requires that, in the event of contractual congestion, the relevant TSO shall offer unused capacity on the primary market at least on a day-ahead and interruptible basis *unless* this would infringe the existing transportation contracts.

94 The term 'refusal' refers to a request to purchase transit capacity from a TSO or special capacity holder which was refused on the basis that insufficient capacity was available for sale (since it has already been sold – i.e. there is contractual congestion).

95 Clearly an efficient TSO would be active in seeking out economically attractive opportunities to gain extra revenue through increases in capacity of its pipelines.

96 The real incentives for a TSO to expand pipelines depends largely on the regulatory regime, if the expansion is indeed realised under that regime. If the pipeline expansion takes place, for whatever reason, outside a regulated regime, the economic incentives of the TSO might be more difficult to measure.

(191) That the issues of equivalent access to transit networks and congestion management are critical to the efficient functioning of the internal market for gas is evidenced by the emphasis that traders, potential new entrants and large customers have placed on these issues in their replies to the Gas Sector Inquiry.

(192) The following sections will present a detailed analysis of these congestion issues. First, an analysis of the extent to which important transit lines on key import routes may be foreclosed as a result of pre-existing long-term legacy contracts is presented. It should be noted that legacy contracts do not only create entry barriers due to foreclosure effects. Even when access can be obtained, new entrants often have no other choice than to reserve capacity with the supply affiliates of former monopoly companies, which are in fact competing suppliers. They cannot obtain such capacity from TSOs within the normal regulated regime. This state of affairs must raise concerns about confidentiality and discrimination.

(193) Following the analysis of legacy contracts on key import routes an overview is provided on the state of congestion on around forty transit pipelines and important entry/exit points connected to transit routes. Finally, an in-depth analysis is undertaken of the issue of congestion management on a number of transit pipelines where the problem of congestion is particularly acute. This chapter ends with a discussion on derogations for new infrastructure investment.

Foreclosure of existing transit infrastructure by legacy contracts

(194) Pre-liberalisation contracts are the main reason why primary capacity is booked long-term by historical incumbents. The inquiry has found that in only two new Member States does it appear that any significant amount of primary capacity on important gas transit routes will become available in the coming years. In all other Member States, primary transit capacity is almost entirely fully booked long term. It also appears that a significant number of the contracts include provisions that can create further impediments to market opening by giving current holders of capacity preferential rights for prolongation of the capacity reservations beyond the originally foreseen end date.

(195) Information on capacity reservations and available secondary transit capacity[97,98] relating to main transit routes in Europe has been compiled and analysed on two main axes of gas flows in continental Europe: the Benelux to Italy axis allowing Norwegian, Dutch and UK gas to flow through France and Germany in the direction of Southern Germany and Italy[99]; and the East to West axis allowing imports of Russian gas into the EU[100] (see Figure 21).

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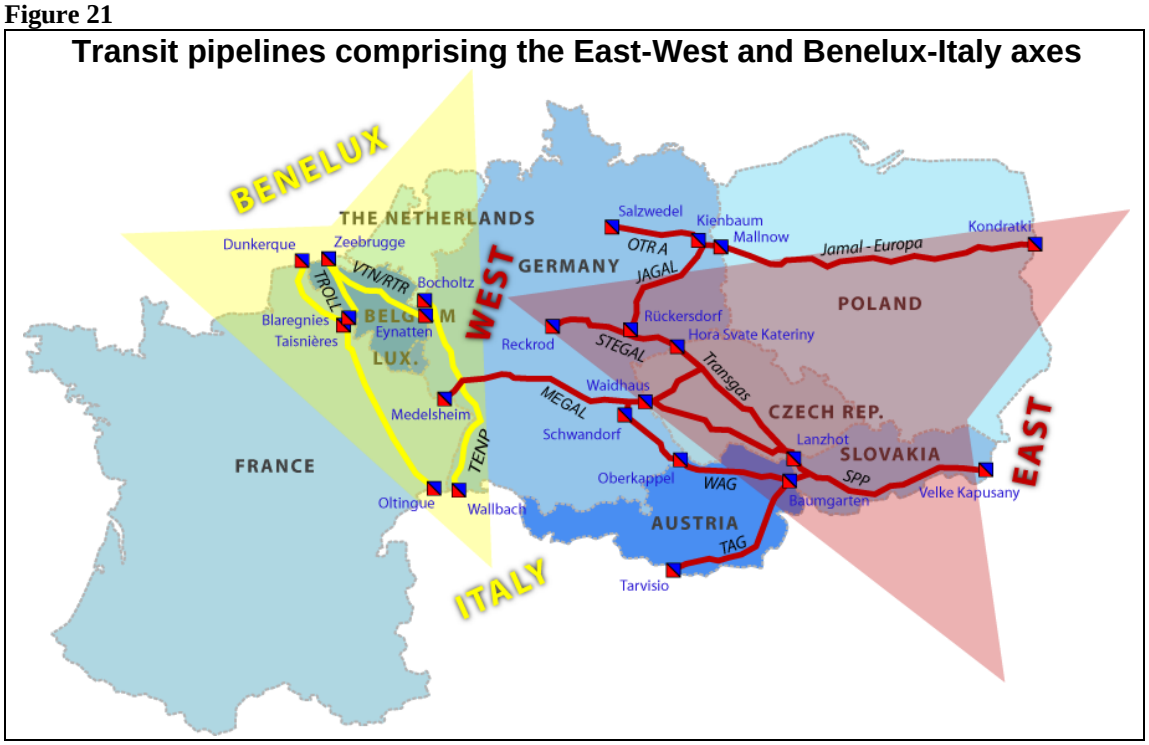
97 Secondary transit capacity is capacity purchased from parties other than the relevant TSO.

98 For the purpose of this analysis, only those secondary capacity trades made by parties having firm rights over a significant share of the total pipeline capacity have been considered. The amount of actual secondary capacity trading may therefore be greater than that presented here.

99 The sample includes data provided by TSO's and primary capacity holders on the following pipelines or network points: the Troll pipeline and VTN pipeline in forward flow on the Belgian network; exit point Oltingue on the French network; the TENP pipeline in Germany; and exit point Bocholtz on the Dutch network. Data on network exit points have been used in where entry/exit access regimes exist in the countries concerned.

100 The sample includes data provided by TSO's and primary capacity holders on the following pipelines: JAMAL-Europa pipeline in Poland, SPP transit pipeline in Slovakia, Transgas transit pipeline in the Czech Republic, TAG pipeline, WAG pipeline in Austria, MEGAL pipeline, STEGAL pipeline, JAGAL pipeline and the pipeline linking up Poland with the NETRA pipeline (Kienbaum to Salzwedel) in Germany (labelled as 'OTR A' on the map).

Figure 21



Source: Energy Sector Inquiry 2005/2006

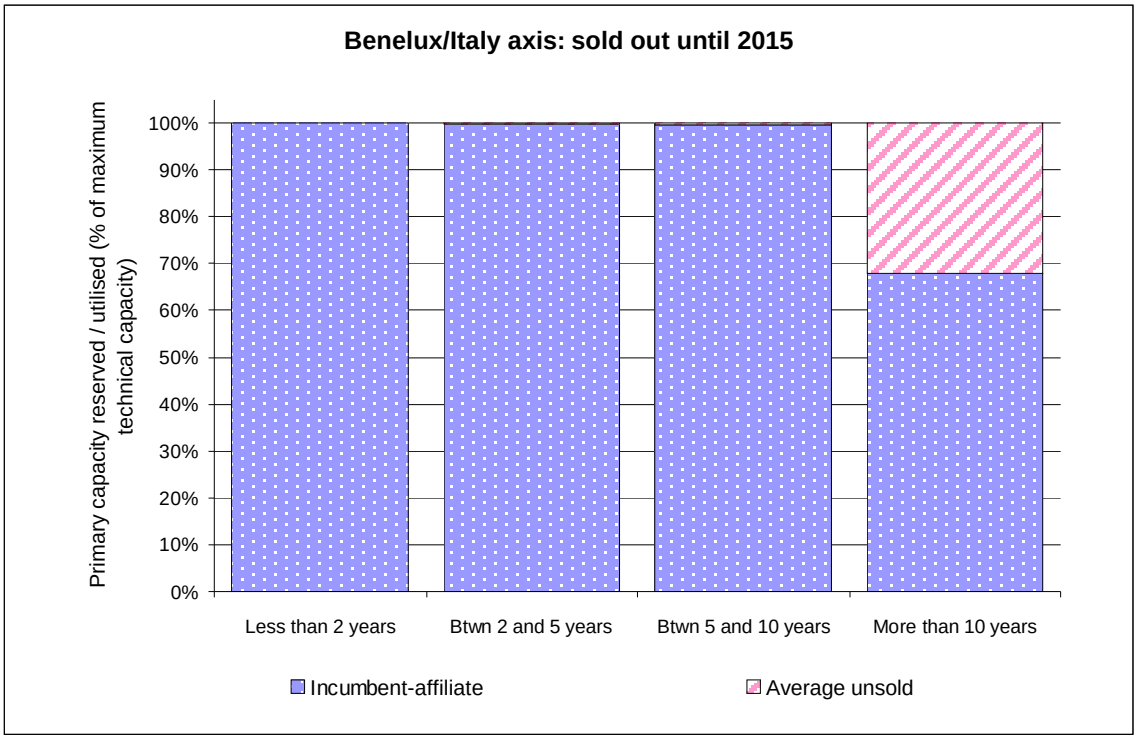
(196) Information has also been gathered on other important transit routes (for instance the import route of Norwegian gas through Northern Germany). However, the large number of different pipeline systems and the high number of operators controlling the capacity on these routes[101] render the access conditions to these transit pipelines opaque, at least for those companies which have not historically flowed gas through these pipeline systems. This opacity also complicates the analysis in the inquiry, which will have to be pursued for the final report.

(197) On the Benelux-Italy axis, the inquiry has found that, on average, primary capacity on these pipelines is booked until 2022[102]. It can be seen from Figure 22 below that the relevant pipelines are fully booked for at least 10 years starting from 1st of June 2005. In other words, all primary capacity on the pipelines of this axis has been attributed long term until 2015. In practical terms, this implies that any company wanting to flow gas on these pipelines will have to request capacity from the incumbent players for at least the next decade in order to obtain capacity on the secondary market. Only after 2015 will some of the primary capacity on certain pipelines become available.

101 The capacity on many pipelines is often split through the so-called 'pipe-in-pipe' approach, where different primary capacity owners of a single physical pipeline act, de facto, as separate TSO's for the capacity they have acquired. This implies, in practice that no single TSO is in charge of allocating the entire available or unused capacity on those pipelines.

102 This analysis has been conducted by taking a volume weighted average duration of each contract for capacity individually. However, this is likely to understates the actual duration effect since, for some pipelines, a single party may strike a number of shorter duration contracts 'back-to-back', which can be considered to have the same effect as a single longer term contract (for instance, three five year contracts which cover the period 2005 to 2020 can be considered equivalent to a fifteen contract).

Figure 22



Source: Energy Sector Inquiry 2005/2006

(198) Moreover, the vast majority of the primary capacity is typically held by only one or two historic players, that are incumbents in their home markets[103]. When capacity is allocated on the secondary market (see Figure 23), roughly half of it is bought by affiliates of the primary capacity owners[104]. An important part of the secondary allocation goes to other incumbents (typically an historic player from a neighbouring country) and to gas producers. Only approximately 5%[105] of longer term capacity allocation goes to new entrants[106].

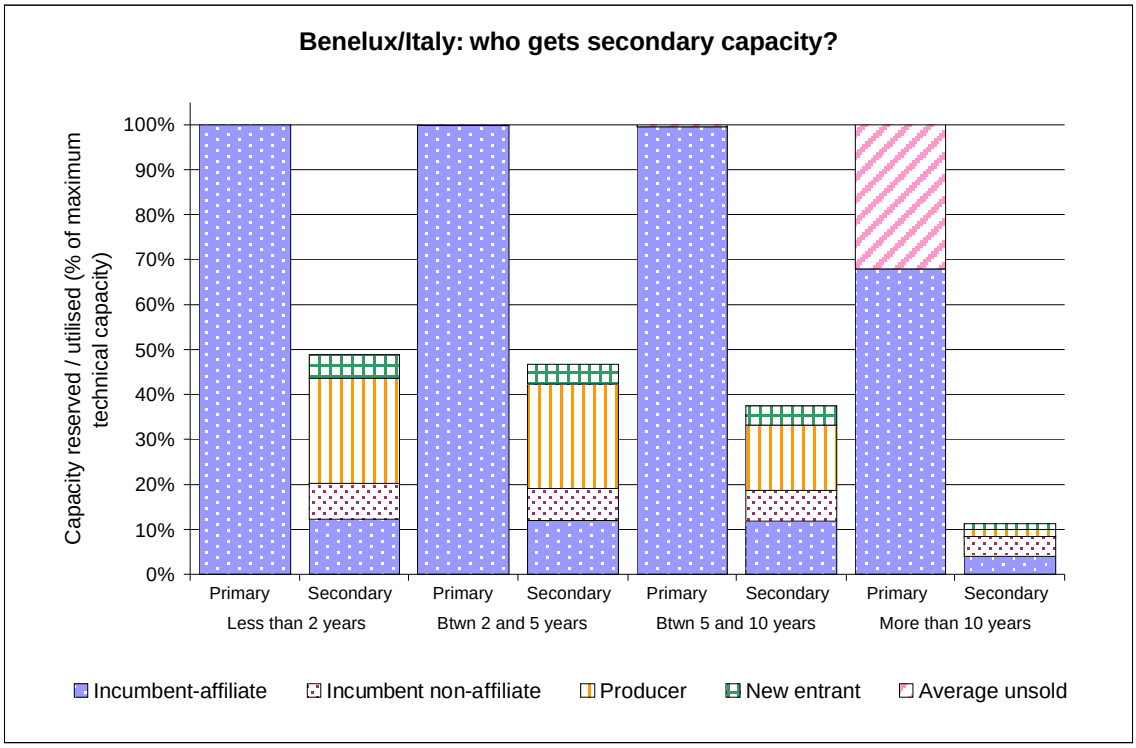
103 Very often, when more than one historic operator owns primary capacity on a transit route, each of these operators will subsequently market capacity of this pipeline on an individual basis as if there were two physically distinguished pipelines (the so-called "pipe-in-pipe" system referred to previously). This means in practice interested companies have to turn to at least two operators for requesting capacity.

104 For the purpose of this analysis, an 'affiliate' company of a primary capacity holder is one which has a significant shareholding in the primary capacity holder, or is one in which the primary capacity holder has a significant shareholding, or is one in which a third party has a significant shareholding as well as having a significant shareholding in the primary capacity holder.

105 This figure is based on a volume weighted average figure for each of the five pipelines and therefore does not necessarily reveal that on three of these pipelines there were no sales to new entrants at all.

106 For the purpose of this analysis, the definition of 'new entrants' includes both newly created wholesale companies and electricity companies becoming active on the gas wholesale markets. Although, in practice, the entry of 'incumbents' into new geographic markets is to develop as an important source of competition, all incumbents' capacity reservations even outside their traditional territory have been classified within the 'incumbents' category, essentially because it is hardly possible to make a systematic distinction between traditional gas flows to their home country and flows enabling them to enter new markets.

Figure 23



Source: Energy Sector Inquiry 2005/2006

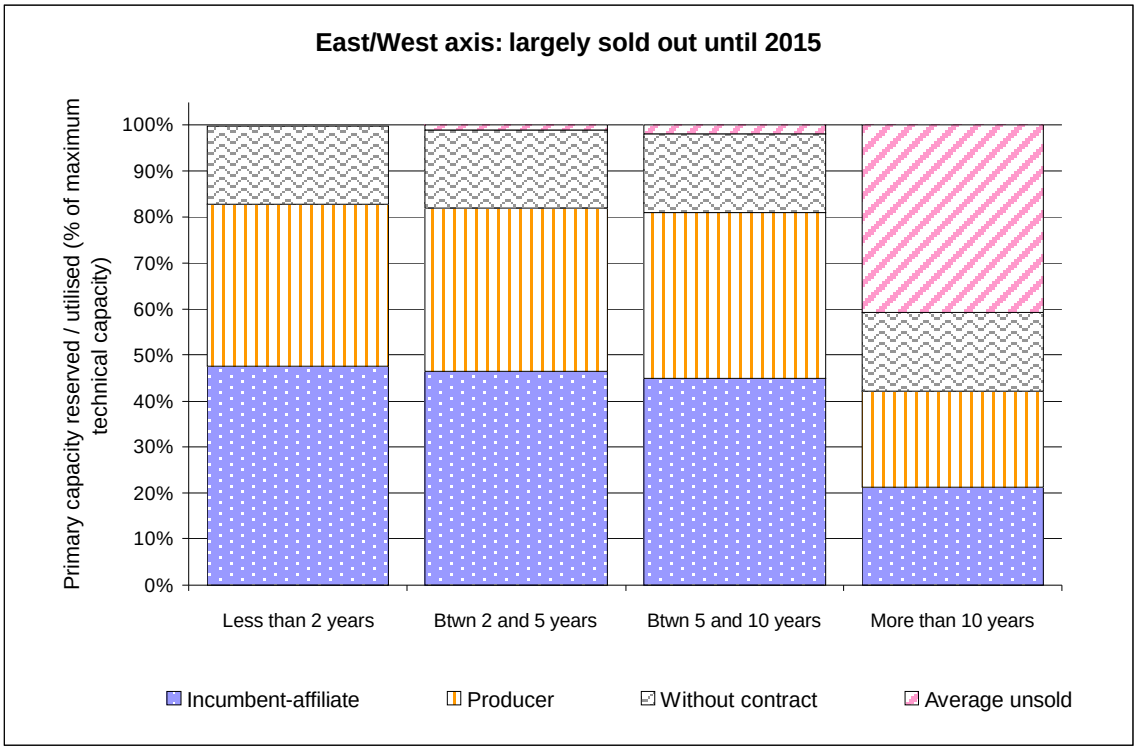
(199) The Gas Sector Inquiry has found that on the East-West axis, a similar situation exists to that on the Benelux-Italy axis, with primary capacity booked on average until 2017. It can be seen from Figure 24 below that the relevant pipelines[107] are almost fully booked (or reserved 'internally')[108] for at least a period of 10 years starting from 1st of June 2005.

(200) Furthermore, as shown in Figure 25, very little primary capacity is subsequently made available on the secondary market, with only around 3% of longer term capacity in the hands of new entrants.

107 For the purpose of this analysis, the SPP transit pipeline system (Slovakia) and the Transgas pipeline system (Czech Republic) have been excluded. As described previously, the Commission has conducted its analysis on a pipeline by pipeline basis but, due to confidentiality concerns, the results presented in this section have been derived by taking an average of the results for each pipeline. Since the average employed is a volume weighted average based on the technical capacity of the individual pipelines, the results of the analysis for the SPP and Transgas transit pipelines tends to dominate the overall picture for the East-West axis, obscuring important trends in the information for other pipelines in the East-West axis, particularly those further to the West. Indeed, the SPP and Transgas transit pipelines appear, on average, to be less congested, both contractually and physically, than the other pipelines included in the East-West axis.

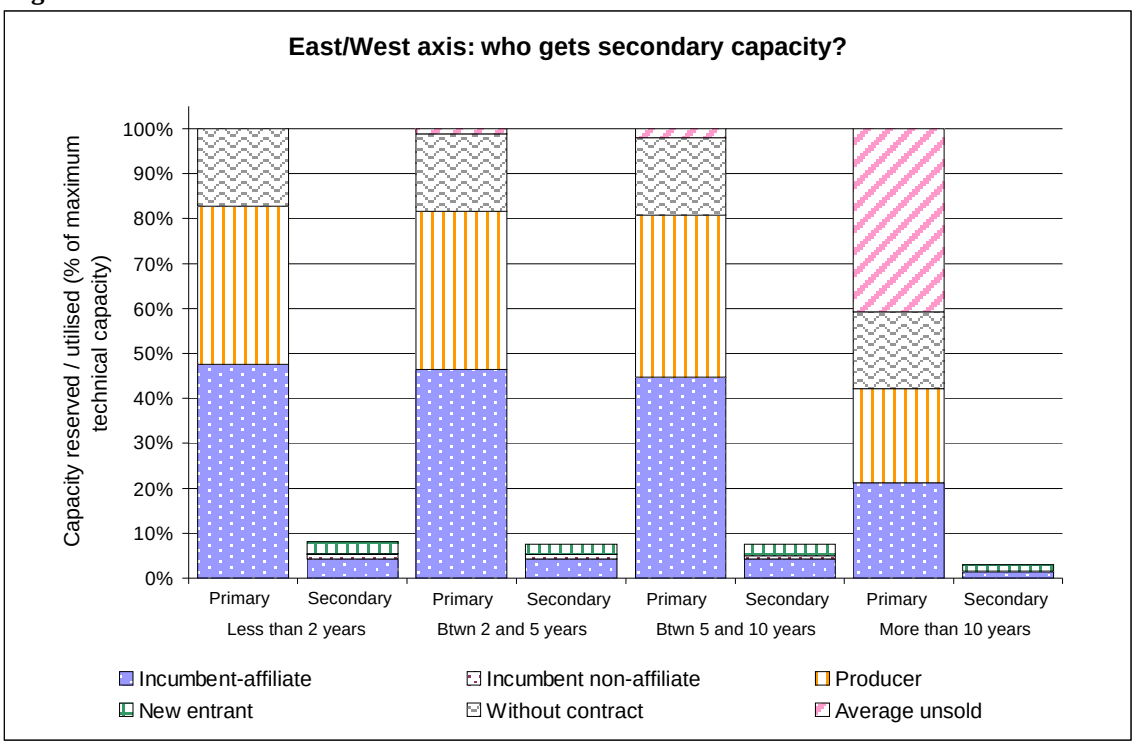
108 For the purpose of this analysis, the inquiry has explicitly identified transit capacity that has not been sold to third parties but has historically been reserved internally by the transit pipeline owner/operator for its own use, without a formal transport contract having been signed between a transport and a supply branch within the same group. This category is identified in the legend as "without contract".

Figure 24



Source: Energy Sector Inquiry 2005/2006

Figure 25



Source: Energy Sector Inquiry 2005/2006

(201) Compared to the Italy-Benelux axis, a significant part of the primary capacity on the East-West axis is held within integrated companies without any formal transport contract having been signed between a supply and transport branch within the company. This situation should improve with the implementation of the unbundling provisions of

the second Gas Directive in Germany, amongst others. Moreover, a comparison between the graphs of the two axes shows that on the Benelux-Italy axis, incumbent wholesalers control almost exclusively all primary capacity rights, whereas on the East-west axis the control of primary capacity is shared between incumbent wholesalers and gas producers.

(202) It cannot be excluded that certain producers will develop into credible competitors that reduce concentration on European gas wholesale markets. The effects on competition of the entry of such companies must, however, be examined in detail in the light of the cooperation which exists between some of these producers and a number of incumbents players. In any case, the effects of long term reservations by large gas producers remain the same for other potential new entrants.

(203) The analysis above has shown that most capacity on crucial transit lines – which are vital for market integration – is in the hands of incumbent players. The transit contracts signed by these historic players before liberalisation will not expire, on average, until around 2020. As a consequence, new entrants have little access to most of the transit pipelines. The difficulty is likely to be even higher - if not impossible, in practice - if the gas has to be shipped over long distances covering several transit pipelines.

Overview of transit congestion in the EU

(204) In order to make a broader assessment of transit-related issues, such as the potential for foreclosure due to pre-existing long term legacy contracts and the extent of congestion on transit pipelines in the EU, the Gas Sector Inquiry has analysed around forty transit pipelines and important entry/exit points connected to key transit routes (see Annex A). These transit pipelines and entry/exit points represent critical infrastructure, linking areas of current and likely future gas production (the Netherlands, Norway, Russia and the UK) and consumption.

(205) This analysis is presented in Table 2 below[109]. The fourth column ("Historical uncontracted capacity") shows the level of potentially available capacity[110] over January 2003 to June 2005. It can be seen that, in this period, there have been very few transit pipelines on which it has been possible to purchase primary capacity. Although, for the most part, little primary capacity has been available, the fifth column ("Historical physical utilisation") shows that in general, for the same period, these pipelines have not been fully utilised[111]. Clearly, in the absence of high levels of utilisation, one might expect significant amounts of interruptible capacity to be made available. However, as can be seen from column six ("Historical interruptible capacity"), the level of

109 The table uses a simple colour scheme to represent the different levels of congestion.

110 For the purpose of deriving this table, the level of uncontracted capacity was determined by taking an average over the period under investigation of the monthly amount of uncontracted capacity. Each cell is given as white if the monthly amount of uncontracted capacity is greater than 5% of the technical capacity, and dark grey otherwise.

111 For the purpose of delivering this table, three measures of physical utilisation were combined to derive a single measure: the maximum monthly utilisation (the monthly utilisation is calculated by taking the monthly average of the daily flows on the pipeline as a proportion of the maximum technical capacity); the peak utilisation (defined as the average of the monthly utilisation for those months where the utilisation was above the total average utilisation for the period under investigation); and the average utilisation. Where the maximum utilisation was greater than 95%, the peak utilisation greater than 80% and the average utilisation greater than 50%, the cell is represented as dark grey. Cells represented as grey or white relate to lower levels of physical utilisation. This data do not take into account daily peaks in utilisation within the monthly periods.

interruptible capacity sold as compared with the level of unused capacity[112] has been relatively low during this period. Finally, column seven ("Future contracted capacity") shows the level of contractual congestion[113] expected in the future on the basis of long term contracts currently in place. Again, it is clear to see that, on most transit pipelines, the problem of contractual congestion is unlikely to improve[114] in the medium and longer term.

(206) The analysis of the broader EU picture in relation to transit capacity largely confirms the findings made on the Benelux–Italy and East-West axes, that most capacity on transit pipelines is in the hands of incumbent players. Further, in the case of primary capacity, this situation is likely to persist for the foreseeable future. It has also been found that although contractual congestion is common, most pipelines are not, in general, experiencing high levels of utilisation. In such circumstances, it would be expected that the relevant TSOs would be releasing interruptible capacity to the market. However, only on a small number of transit pipelines has a substantial amount of interruptible capacity been sold, indicating that these TSOs may not be maximising the efficient use of pipeline capacity.

Further analysis of congestion on five key pipelines

(207) In order to make a more detailed analysis of congestion issues further analysis was undertaken of five key transit pipelines on which there appears to be a particular problem with congestion. These transit pipelines are the TAG pipeline in Austria; the TENP and MEGAL pipelines in Germany; and the VTN/RTR in the forward flow direction (West to East) and TROLL pipelines in Belgium[115].

Contractual congestion

(208) In order to assess the state of contractual congestion on the five highly congested transit pipelines, an analysis of the extent of future contracted capacity on these pipelines was first made. It can be seen from Figure 26 below that this analysis confirms the general picture found for the Benelux-Italy and East-West axes, where primary capacity is almost entirely contracted long term to the shipper businesses affiliated to the relevant TSO (over sixteen years in the case of these five pipelines).

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112 The level of interruptible capacity was determined by taking an average over the period under investigation of the monthly amount of interruptible capacity made available. Each cell is given as white if the monthly amount of interruptible capacity is greater than 10% of the average unused capacity (unused capacity is capacity contractually booked but not flowed against), and dark grey otherwise. This data do not take into account daily peaks in utilisation within the monthly periods.

113 For the purpose of deriving this table, the level of contractual congestion was determined by examining the amount of primary capacity reserved over four time periods: from 1 June 2005 to two years ahead; from two to five years ahead; from five to ten years ahead; and from ten to twenty years ahead. A pipeline was deemed as being congested under the following conditions: for the first time period, over 90% of the maximum technical capacity has been reserved; for the second time period, over 90% has been reserved; for the third time period over 70% has been reserved; and for the fourth time period over 50% has been reserved. Where, a particular pipeline is deemed to be congested for three or more of these time periods, the cell is represented as dark grey. Cells represented as grey or white relate to lower levels of congestion.

114 Notwithstanding any issues in relation to new entrants sourcing gas, this situation is only likely to improve 'organically' if new entrants can build alternative transit infrastructure. Failing this, it may, in the future, become necessary to introduce regulatory and/or competition law measures to address this situation.

115 It must be stressed that this selection does not imply that other transit pipelines, or transit routes that cross entry/exit regimes, should be considered as not congested.

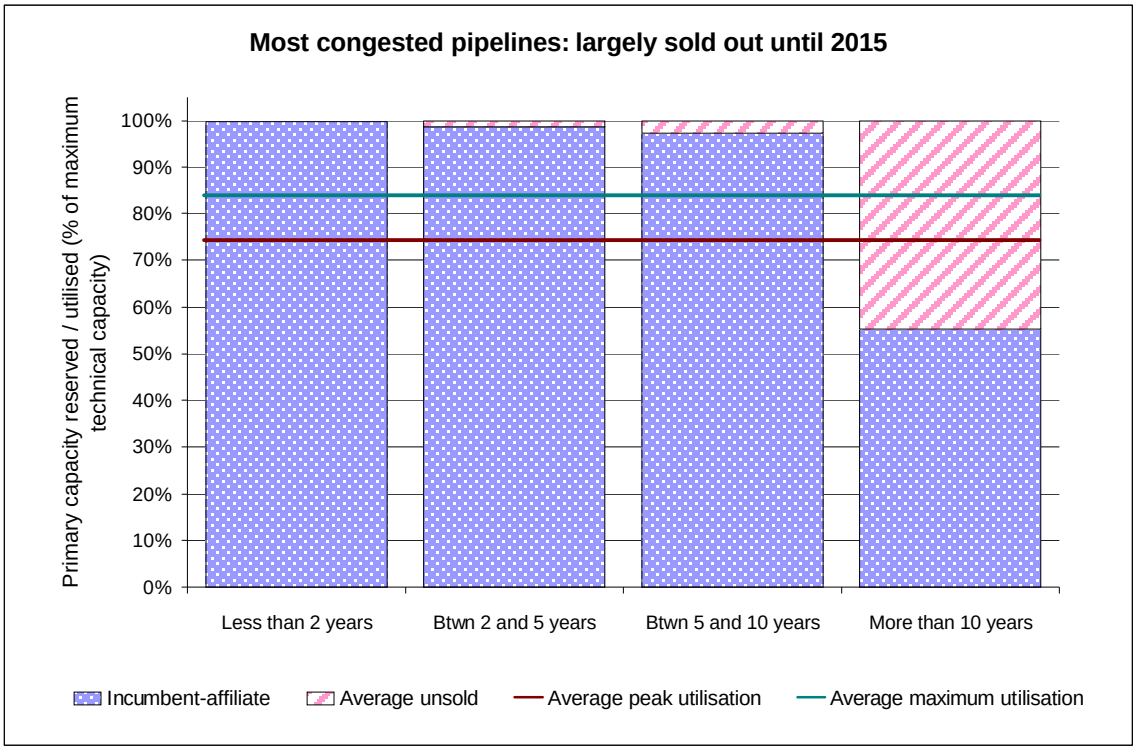
Table 2

Congestion on transit pipelines in the EU

Pipeline	Technical capacity *mcm / day*	Route	Historical uncontracted capacity	Historical physical utilisation	Historical interruptible capacity	Future contracted capacity
SPP	315.9	E-W				
Transgas	180.5	E-W				
TAG	95.3	E-W				
JAGAL	80.1	E-W				
Ex Hilvarenbeek	67.7	N-S				
JAMAL-Europa	67.2	E-W				
MEGAL Nord	57.1	E-W				
IUK FF	54.8	N-S				
En Taisniere	50.4	N-S				
En Dunkerque	49.1	N-S				
NETG	44.5	N-S				
Ex Bocholtz	43.9	N-S				
TENP	40.5	N-S				
TROLL	40.5	N-S				
METG	40.1	N-S				
STEGAL West	36.0	E-W				
VTN/RTR FF	30.2	N-S				
Slochteren	27.5	N-S				
Ex 's Gravenvoeren	27.1	N-S				
BEB OTR 1	20.0	N-S				
STEGAL East FF	20.0	E-W				
Ex Oltingue	19.7	N-S				
BEB OTR 8	19.3	N-S				
En OSZ RG	18.6	N-S				
WAG	18.5	E-W				
En Emden EPT	18.2	N-S				
SEGEO	17.9	N-S				
En Emden NPT	13.1	N-S				
MEGAL Sud FF	11.1	E-W				
RWE OTR 3	10.9	N-S				
BEB OTR 3	9.6	N-S				
BEB OTR 5	6.9	N-S				
BEB OTR 10	6.7	N-S				
DEUDAN	6.6	N-S				
RWE OTR 2	3.7	N-S				
BEB OTR 7	2.6	N-S				
RWE OTR 1	1.6	N-S				

Source: Energy Sector Inquiry 2005/2006

Figure 26



Source: Energy Sector Inquiry 2005/2006

(209) It also appears that a significant number of the contracts reserving primary capacity on these five transit pipelines can create further impediments to market opening by giving current holders of capacity preferential rights for prolongation of the capacity reservations beyond the originally foreseen end date. Most prominently, a number of pre-liberalisation transit contracts were prolonged only few months before regulated third party access regimes were to be introduced. In cases where new major energy infrastructure is to be constructed, it can be argued that it may be necessary for the TSO to guarantee the financial viability of the project by signing longer term 'ship-or-pay' transport contracts for a substantial part of the pipeline's capacity. However, the prolongation of existing transport contracts cannot benefit from such a justification, especially when the cost of the construction of the pipeline concerned has already been (largely) amortised.

(210) The practical problems faced by new entrants when encountering extensive contractual congestion could be mitigated by effective measures to facilitate the release of unused capacity, both in terms of longer-term firm capacity on the secondary market and shorter-term capacity. Indeed, it results from article 5 of the Gas Regulation, which itself builds on the obligations outlined in articles 18 and 21 of the second Gas Directive, that TSOs have an obligation to maximise the capacity made available to interested shippers, including unused capacity, under the conditions foreseen by the Gas Regulation. These obligations arising from the Regulation apply both to (regulated) transport and to transit, which, as has been referred to earlier, is sometimes left largely unregulated at the national level. Obligations similar in nature would apply to TSOs or other companies – i.e. special capacity holders – which might be considered as dominant on any given transport market between two geographical locations. The release of unused capacity appears to be all the more necessary when the capacities concerned have been unused for longer periods of time.

(211) It can be seen from Figure 26 that the five highly congested pipelines under analysis are not, on average[116], fully utilised. Therefore a substantial amount of unused capacity could be made available to the market. However, in the period under investigation, on only one of these five transit pipelines was a meaningful amount of interruptible capacity released. Indeed, no interruptible capacity whatsoever was released on three of these (highly contractually congested) transit pipelines, despite two in particular having a significant proportion of their maximum technical capacity unused. Further, on one pipeline where the entire primary capacity has been sold to an affiliate of the relevant TSO until almost 2030, no congestion management mechanisms whatsoever are in place. This is despite the average utilisation being only slightly over 50% of the maximum flows possible[117].

(212) That a lack of effective congestion management can lead to inefficiencies is shown in Figure 27 below. Here, an analysis has been made of the extent of refusals for requests for capacity of relatively short durations over periods when utilisation is traditionally low (i.e. summer). The chart shows the result of this analysis for the period summer 2004 on one of the highly congested pipelines under investigation[118]. The solid line represents the actual physical flow recorded on the pipeline in question and the dashed horizontal line represents the maximum possible flow. The hashed area represents the volume of requests for capacity over the summer period refused by the TSO/SCH in question. It can be seen that, had all these requests for capacity been granted and had this capacity been flowed against in full by its new holders, the level of utilisation of this particular pipeline would have been considerably greater[119].

(213) As set out previously, TSOs and special capacity holders insist that the UIOLI principle does not apply to transit pipelines at all, or at least that it cannot be applied effectively to transit, since their 'ship-or pay' transport contracts allow the incumbent capacity holder to re-nominate typically until two hours before the relevant gas flows are to commence. The apparent requirement for such short term flexibility in transit pipeline gas implies a significant degree of uncertainty, for instance in the demand of the customers supplied via the transit pipeline. There may well be more efficient outcomes possible overall, whereby the flexibility requirement is met through other sources, allowing the transit pipeline to be used more efficiently (i.e. increasing its utilisation closer to the maximum possible). However, in the absence of effective competition, the economic drivers on the market to seek out such solutions are diluted.

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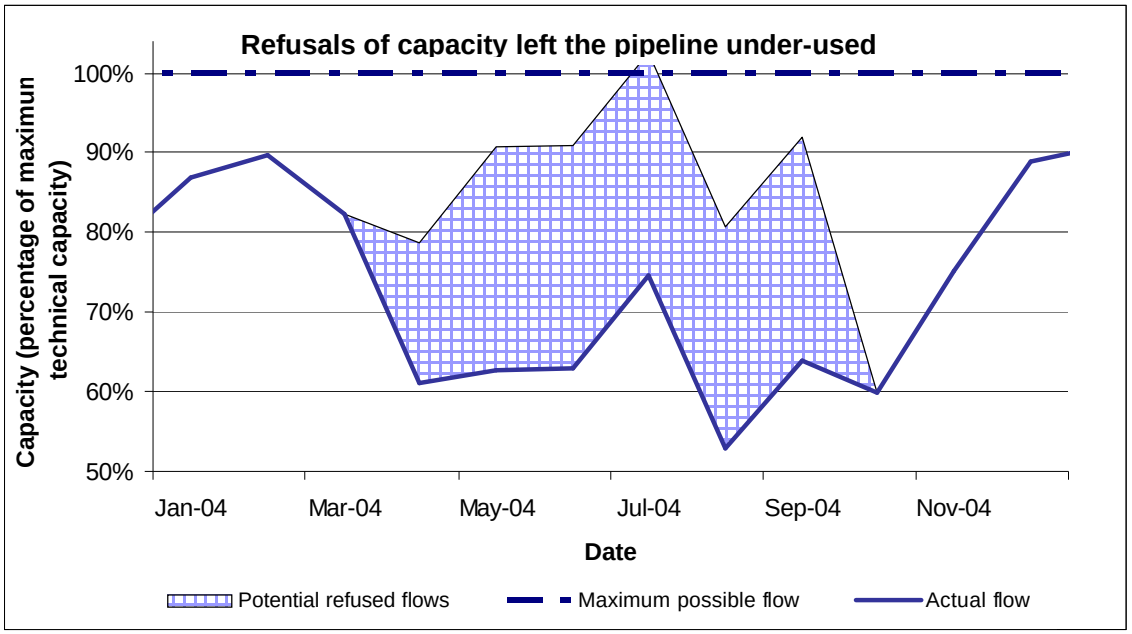
116 In the graph, the term "average maximum utilisation" was calculated by taking for each pipeline of the axis the (typically winter) month where any given pipe has been most used and taking an average over all the pipelines of that axis. "Average peak utilisation" uses the same methodology, but applied not merely on the month in which each of the pipes was used most, but for all months where use of the pipeline was more than the overall average usage rate of the pipeline. Thus the first line provides an idea of capacity which could be made available long term (for a full year including winter), whereas the second gives a general impression of the average unused capacity.

117 Indeed, the maximum monthly flow was also relatively low at just 80% of the maximum flow possible.

118 For confidentiality reasons, it was decided not to specify the name of this pipeline in this report.

119 The result presented in this chart is more broadly reflective of the situation on most congested transit pipelines. However, it should be noted that, in many cases, the answers submitted by TSOs and SCHs in relation to refusals was incomplete (for instance, where no record was made by the TSO or SCH of capacity requests made to it) and therefore a wider analysis taking into account a greater number of pipelines has not been possible. In mitigation of this, it should also be noted that, since it is common knowledge in the industry that many of the transit pipelines in the EU are contractually congested (i.e. there is no capacity available for sale), we consider that the data reported in relation to refused requests for capacity is likely to underestimate the actual level of unsatisfied demand since a new entrant, for instance, is unlikely to request capacity if they expect to be refused or have been refused in the past.

Figure 27



Source: Energy Sector Inquiry 2005/2006

(214) The Gas Sector Inquiry has found that a number of contracts reserving primary capacity include provisions giving the capacity holders preferential rights for prolongation. This means that new entrants may not be able to compete on an equal footing even after the current terms of existing long-term transit contracts expire (typically fifteen to twenty years hence). Further, a detailed analysis of the utilisation of a number of pipelines has revealed that, in some cases, even when congestion is severe, no effective congestion management measures have been put in place. In one example, where the entire primary capacity has been sold to an affiliate of the relevant TSO until almost 2030, no congestion management mechanisms whatsoever are in place, despite the average utilisation being only slightly over 50% of the maximum flows possible. This analysis has revealed that there may be significant scope to increase efficiency in the allocation of transit capacity, in particular in respect of off-peak periods.

Physical congestion

(215) As discussed previously, a particular transit pipeline can be both physically and contractually congested. Whereas the latter presupposes that not all booked capacity is systematically used to its maximum extent, the former indicates that the pipeline concerned appears indeed to be used up to its physical limits and no additional demand for capacity can be accommodated. In the case of the five highly congested pipelines under analysis here, only three can be said to be both contractually congested and also experiencing some level of physical congestion[120]. However, where there are no effective congestion management measures in place, as is the case with a number of the pipelines here, pipelines that are only contractually congested can also exhibit the 'symptoms' of physical congestion in that unused capacity is not being efficiently released to the market.

120 Based on their actual level of utilisation. The nature of this physical congestion is transitory, however, since it only tends to arise around a small number of peak periods during the year. The fact that there is some degree of physical congestion means that UIOLI rules, though helpful during certain lower consumption periods, cannot remedy the structural problem of lack of capacity.

(216) In this context it is necessary to determine how efficiently the company (companies) owning the infrastructure respond to continuous demand from the market for more capacity. That significant demand for additional capacity is present can be seen from Figure 28. The chart shows the volume of requests[121] for long term capacity (greater than five years in duration[122]) that were refused by the relevant TSO/SCH[123]. It can be seen for a number of the pipelines that the volume of requests is material in comparison to the existing technical capacity of the pipeline, which indicates a significant level of unsatisfied demand for transit capacity[124]. Not every request for capacity presented here would have necessarily resulted in a firm bid for extra capacity[125]. However, it should be pointed out that, in an efficient market, TSOs would be proactive in seeking out and responding to such investment signals in a timely manner. It is not clear to the inquiry that the TSOs in question have in place, as a matter of course, systems to facilitate this activity[126].

Transit and hub liquidity

(217) Complexity seems to be a common feature of the transit market, particularly as regards the way in which different promoters and financiers of certain gas transit pipelines have been allocated long term primary capacity in certain Member States. For instance, the location of the Zeebrugge hub along the VTN transit pipeline in Belgium does not necessarily facilitate liquidity on that hub and indeed different market players have complained about this issue[127].

(218) From a physical perspective, the location of the Zeebrugge hub means that gas from other sources in the Zeebrugge region, for instance Norwegian gas landed at the Zeepipe terminal, gas landed at the Zeebrugge LNG terminal, local stored gas, or gas from the domestic transportation system, cannot easily be transported to the hub. From a contractual perspective, the capacity of the VTN transit pipeline (which incorporates the location of the Zeebrugge hub) was allocated long term to Distrigas & Co (an affiliate of wholesale gas supplier Distrigas) shortly before liberalisation. Therefore, any shipper seeking to ship gas between the hub and the interconnector will have to request access to Distrigas (& Co) – or possibly another company having obtained secondary capacity from Distrigas (& Co) – and not from an unbundled TSO. It is considered likely that this peculiar arrangement has led to congestion at the Zeebrugge hub and has consequently hampered the development of higher levels of liquidity at this location.

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121 The volume is expressed as a proportion of the maximum technical capacity of the relevant pipeline.

122 This time period has been chosen to highlight the type requests that TSOs may consider required to stimulate additional investment in a pipeline to increase its capacity.

123 For confidentiality reasons, DG Competition has chosen not to specify the names of these five pipelines in this chart.

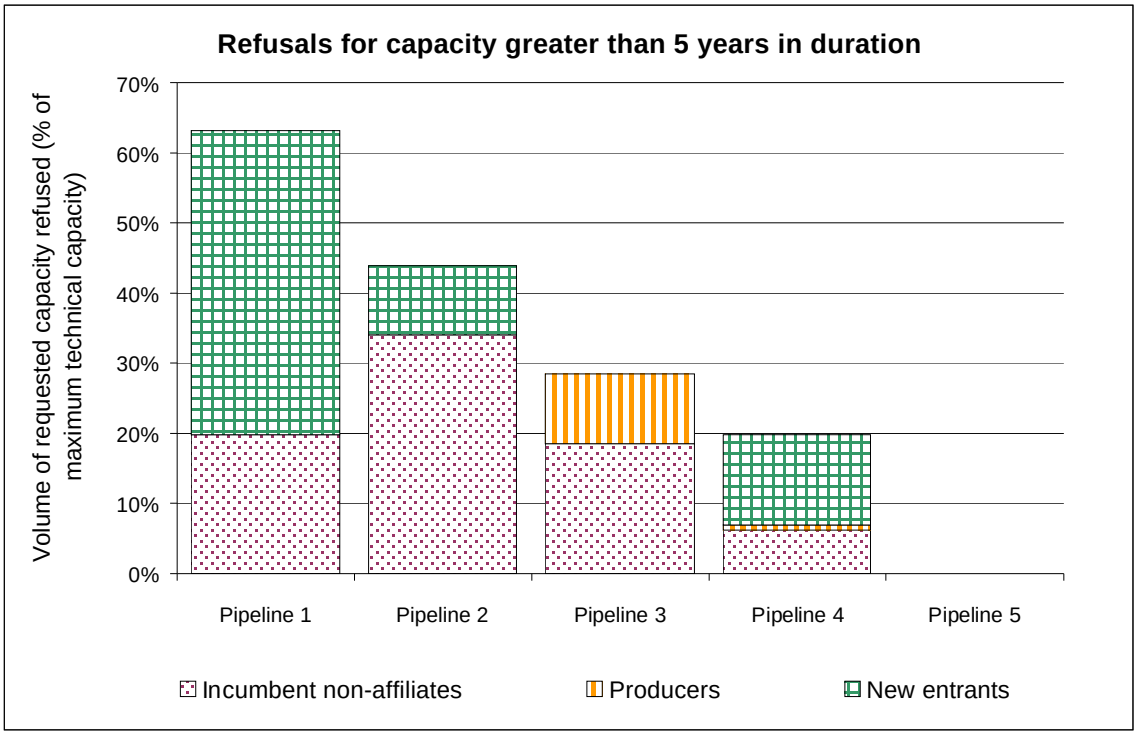
124 As set out earlier, we would note that not all requests for capacity may have been recorded by the relevant TSO/SCH and, in addition, some market participants may have been discouraged from requesting transit if they expect to be refused. Therefore we consider that the requests presented here understate the actually level of unsatisfied demand for additional transit capacity present in the market.

125 TSOs have indicated that, in considering whether to invest to increase the capacity such infrastructure, firm bids for substantial volumes of capacity over long periods are required in order to offset the risk that the investment will become stranded.

126 Where a pipeline falls within the competencies of one or several energy regulators, one should presume that these regulators are ensuring that the necessary network enhancements are being made. However, as referred to earlier, it appears that a number of transit pipelines are still not completely under the scrutiny of a relevant regulator. Further, where a particular pipeline (for instance an interconnector) falls under the remit of more than one regulator, it may be the case that cooperation between the two regulations on an issue such as network enhancements is difficult due to their different aims and objectives.

127 See also in this sense the opinion published by the Belgian energy regulator CREG in September 2005: http://www.creg.be/pdf/Opinions/2005/GT112005/GSD-051017-rapportdeconsultationv6-EN.pdf

Figure 28



Source: Energy Sector Inquiry 2005/2006

New infrastructure and exemptions

(219) The nature of gas flows across the EU is likely to change significantly over the medium- to long-term due to factors such as the relative decline of domestic production (for instance from the UK Continental Shelf) and the drive to further diversify supplies (for instance through an increase in LNG imports). In order to continue to meet the needs of end consumers, the market will need to ensure that the necessary transmission infrastructure is in place to cope with such a dynamically changing pattern in flows. This will most likely require substantial investment in new infrastructure such as transit pipelines, interconnectors and LNG-terminals.

(220) A number of projects are already underway either to construct new transport infrastructure (for instance the BBL interconnector from the Netherlands to the UK) or to upgrade existing infrastructure by increasing its capacity[128]. Since such projects require significant capital investment, the nature of the financing arrangements is key in order to ensure their viability. Typically, project developers attempt to mitigate their risk by long-term contracts, guaranteeing the developers sufficient future revenue to meet the costs of financing the project. It is important, therefore, that the regulatory regime strike a balance between providing the right incentives to build new capacity and ensuring that any long-term contracts do not have detrimental effects on competition.

(221) The second Gas Directive requires that transport infrastructure must be subject to regulated third-party access. This includes obligations on the TSO to ensure that the

[128] A number of companies have recently announced capacity enhancements, for instance Fluxys for the VTN pipeline, GTS for some border entry and exit points of the Dutch system and TAG GmbH for the TAG pipeline. However, in light of the fact that these projects are likely to take a number of years to complete, it is not clear to DG Competition that the significant unsupplied demand for transit services across these routes is being met in a timely fashion. Further, it appears that other congested pipelines, for instance the TENP pipeline, are currently not being considered for expansion.

rules for access to the system are non-discriminatory and also requires that the tariffs charged for using the system are approved by the relevant regulatory authority. However, a derogation possibility exists in the second Gas Directive by which new or upgraded infrastructure can be exempt from the third-party access rules[129]. The granting of an exemption is subject to a number of conditions, including, crucially, that the exemption not be detrimental to competition[130].

(222) The key facts to consider in assessing whether this condition is likely to be satisfied concern the nature of any contracts allocating capacity on the new or upgraded infrastructure, in particular the counterparties concerned, the scope of the contracts, and their duration. For instance, it has been widely acknowledged[131] that any capacity allocated on the new or upgraded infrastructure should be allocated pursuant to a pro-competitive process, such as an 'open season' or similar procedure, organised before the expansion and allowing for interested third parties to participate in the expansion.

(223) New infrastructure can, by increasing cross-border competition and competition between outside EU producers, often have pro-competitive effects when allowing for new competitors in national markets or new sources of gas to reach the EU. Moreover, the financial incentives for large infrastructure projects are obviously of key importance, as projects without appropriate financial security will not take off at all. However, the existing long term reservations on transit lines demonstrate the risk of cementing market shares in destination markets. Indeed, it appears that the additional primary capacity resulting from previous capacity increases on the five highly congested pipelines under analysis has, for the most part, ended up in the hands of the companies that already controlled the pre-existing primary capacity.

(224) Therefore, it is important to underline that the conditions of any open season are crucial to its success in terms of yielding an outcome that will not be harmful to competition. For instance, do the conditions indeed allow for different types of companies (both incumbents and new entrants) to participate in the expansion? The desire of the project developer to lay-off as much risk as possible through locking-in long term contracts means that the level and length of financial commitments required from the participants is crucial to the success (in terms of competitive benefits) of any open season. It is evident that it will be much harder for new entrants, whose market share is not (yet) established to commit themselves to ship-or-pay contracts for 20 years, especially when the existing capacity on transit lines is booked long term.

(225) It is therefore important, in assessing whether to grant an exemption[132] from third-party access for new or upgraded transit pipelines and interconnects, to ensure that the conditions of any procedure for allocating capacity do not perpetuate the current level of foreclosure observed on existing transit lines. Indeed, the level of foreclosure

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129 However, it should be noted that the receipt of an exemption is not a requirement in order for new infrastructure to be built. Indeed, the CEER paper 'Investments in gas infrastructures and the role of EU national regulatory authorities' states that "In some cases, new pipelines […] may benefit of an appropriate enhanced [regulated] rate of return to compensate for higher risks" and that "The possibility for such exemptions is clearly envisaged to be an exception to the default arrangements".

130 The exemption criteria are set out in full in Article 22 of the second Gas Directive.

131 See again, for instance, the CEER paper 'Investments in gas infrastructures and the role of EU national regulatory authorities'.

132 Even if a project developer chooses to make an investment in new infrastructure under a regulated regime, the points made here concerning capacity allocation are still relevant.

established for the existing transit lines pleads for a more pro-competitive approach with regard to expansion projects.

Conclusion

Cross-border sales do not currently exert any significant competitive pressure in EU wholesale markets. The concentration of the historical incumbents in their domestic markets is mirrored by their lack of sales in other markets. Swaps are not a marginal phenomenon and can substitute physical transport of gas. However, they are largely tools used by incumbents. New entrants are unable to secure *primary* transit capacity on key transit routes due to the predominance of long-term contracts signed between incumbent TSOs and, typically, their supply affiliates. This situation is expected to persist for the term of the pre-liberalisation legacy contracts (typically fifteen to twenty years of duration) but also potentially beyond this time due to the existence of provisions allowing these contracts to be extended.

On a number of the most congested transit pipelines the volume of requests for additional capacity (much of it from new entrants) is material in comparison to the existing technical capacity of these pipelines, indicating a significant level of unsatisfied demand for transit capacity.

Even in instances where the capacity of particular transit lines has been increased, the resulting new capacity has, for the most part, ended up in the hands of the companies that already controlled the pre-existing primary capacity. The current process for financing new investment risks cementing market shares in destination markets and forming a barrier to smaller players participating in the market.

Moreover, access to *secondary* transit capacity, which should be in theory open to new entrants, has in reality not been obtained by them, with the majority being secured by incumbent suppliers from other countries or large gas producers. Due to the lack of effective congestion management mechanisms on the majority of transit pipelines, it is seldom possible for new entrants to secure even smaller volumes of short-term, interruptible capacity.

II.4. Transparency

Introduction

(226) Lack of transparency prevents new entry, as market operators are unable to take sound commercial decisions without sufficient information. Transparency regarding infrastructure (available transport capacity, available storage and other aspects of the gas markets such as balancing) creates a level playing field as it ensures that all operators have access to the same information. Transparency also plays an important role in building confidence in the market. This has in particular been highlighted where unbundling requirements must be fulfilled. Reliable and publicly available information on transport capacity will reassure users that they are treated equally and thereby demonstrate an appropriate application of the unbundling requirements.

(227) It may be feared that excessive transparency could facilitate collusion between the major markets players, particularly on an oligopolistic market. A balance must certainly be found as to what data is published and how it is published, in order to improve transparency without enabling collusion. However, the existing lack of transparency means that it is more necessary to enhance transparency than to limit it. Moreover, gas infrastructure assets are to a large extent monopolies and not part of competitive markets.

(228) The sector inquiry confirms that gas wholesale operators have contrasting views on the amount of information available on network capacity. Incumbents are usually satisfied, whereas most new entrants find that information is lacking. Networks users were asked about the importance of specific information elements to establish what information should be made available. In view of the importance of transit for the creation of a single gas market[133], the preliminary report has focused on transparency in access to transit lines and concentrated on certain aspects, namely on the impact of the so-called "three or more" rule and on information on unused capacity. The preliminary report also examined transparency regarding storage.

II.4.1. Transparency on access to transit pipelines

(229) Generally, the sector inquiry findings show that, despite a certain amount of information being published[134], transparency should be improved. A number of TSOs indicated that they publish whether capacity is available in the form of traffic lights, without accompanying it with precise numerical information. TSOs added that network users should contact them to receive more detailed information.

(230) As explained above, the situation in transit is complicated by the fact that primary capacity is often booked for long periods by incumbent players. Network users complained that they need to turn to a competitor to have access to transit capacity. Currently, they must ask primary capacity holders for detailed information in order to

133 See section "Access to transit pipelines"

134 For an analysis of the implementation of the second Guidelines of Good Practice see the CEER "Monitoring report 2004 concerning compliance with the guidelines for good third party access practice to gas transmission systems". We concentrated on the analysis of transparency regarding transit lines, whereas the regulators worked mainly on national networks.

optimise their portfolio of transport contracts. They would therefore prefer to see capacity administered by an independent TSO.

(231) A number of network users complained about the lack of transparency regarding available transit capacity and difficulties encountered in getting access to it in a timely and effective manner. The incumbent supplier in Belgium has acquired all capacity rights on the VTN and the Troll pipelines (Zeebrugge-Blaregnies) and does not publish information on available capacities but provides it only upon request. Its stated reason for not publishing information is the need to evaluate each capacity request on a case-by-case basis, and the fact that capacity reservations in forward and reverse flows at entry and exit points influence each other[135].

(232) The inquiry confirms that information should also be easily accessible (see Table 3). Generally, about 74% of network users favoured centralised systems of information, be it a European-wide web-platform or a sole website for each transit line. About 24% answered "other" and specified that information should be published by the TSO. Some respondents added that the TSO would be acting on behalf of the primary capacity holder.

Table 3

According to the respondents, information on the capacity situation on transit pipelines should be:	
	% of total number records
Centralised for all transit pipelines and published on an EU-wide web-platform	29.8%
Other - Specified: TSO	23.4%
Published on the website of each primary capacity holder	21.3%
Centralised for all primary capacity holders and published on a sole website for each transit line	21.3%
Available only upon request to each primary capacity holder	4.3%

Source: Energy Sector Inquiry 2005/2006

(233) The regulatory framework has attempted to remedy the lack of transparency regarding access to networks first through Guidelines of Good Practice[136], more recently through the Gas Regulation. Basic principles regarding transparency requirements are set out in Article 6 of the Regulation. These are applicable to gas transmission networks, including those lines which are generally considered as "transit lines". TSOs should publish information on the services they offer, on tariff derivation and on the capacity situation.

(234) In particular, Article 6.3 of the Regulation - which is to be read in the light of the obligation imposed on TSOs to maximise the capacity made available to network users - obliges these TSOs to make information available to the public on at least technical,

135 For further information on this issue, see "Le fonctionnement du marché belge, rapport de consultation de la CREG », September 2005.

136 The First Guidelines of Good Practice were adopted in 2002.

contracted and available capacities. This information should be on a numerical basis, and cover all relevant points including entry and exit points[137].

(235) Answers received within the sector inquiry emphasized the importance of rather detailed information. Information on available capacity is considered, unsurprisingly, indispensable by most users (about 79%) and important by about 15% of them (see Table 4). Information on maximum technical capacity is also considered important by network users.

Table 4

According to the respondents, information on available capacity is:	
	% of total number records
Indispensable	78.7%
Important	14.9%
Useful	4.3%
Not useful	2.1%

Source: Energy Sector Inquiry 2005/2006

(236) Network users would like information on the capacity situation to refer to daily or hourly periods. Most of those who chose an alternative option specified that information on capacity should refer to periods coherent with the balancing regime: hourly if balancing is hourly, daily for daily balancing.

(237) Information on the capacity situation should be kept well up-to-date. The majority of network users would like to see information up-dated daily (about 43%) or even in real-time (about 30%). Most of those who answered "other" explained that the frequency of the up-dates should depend on the balancing regime. About 10% of users found updates once a week would be sufficient.

(238) All network users replying consider long-term forecasts of available capacities to be at least useful. Indeed, about 45% found them indispensable, about 35% important and about 20% useful. According to most users, these forecasts should refer to daily or monthly periods (see Table 5). Some networks users also indicated that the forecasts should be in accordance with the balancing regime (hourly or daily). Network users also mentioned that forecasts of available capacities should cover the same number of years as for which capacity can be contracted.

[137] Guidelines annexed to the Regulation, which provide for a minimum degree of harmonisation. These guidelines can be amended by the Commission through the comitology procedure. They define technical information necessary to gain access to the system, relevant points for transparency requirements and the type of information to be publish as well as the schedule for publication of information. Guidelines on third party access services and on the principle underlying capacity allocation mechanisms and on the application of congestion management procedures are also annexed to the Gas Regulation.

Table 5

According to the respondents, information on forecasts of available capacity should refer to:	
	% of total number records
Daily periods	38.3%
Monthly periods	25.5%
Other - please specify below	21.3%
Hourly periods	12.8%
Weekly periods	2.1%

Source: Energy Sector Inquiry 2005/2006

(239) Network users made similar considerations on information regarding historical flows. According to the vast majority of network users, information on historical flows should cover at least the last three to five years. A number of network users specified that information on historical flows since the start of operation of the pipe should be available. Information should be detailed; according to the majority of users it should concern daily or hourly periods. Some network users specified that it should be in line with the balancing regime; while others indicated that it should be particularly detailed when referring to peak periods. Information on historical patterns of interruption was considered useful by about 38% of network users, important by about 30% and indispensable by about 25% of them.

II.4.2. The three or more rule

(240) According to the Gas Regulation, the amount of information made public can be limited if making this information public would risk harming legitimate commercial interests of supply companies shipping gas on the lines concerned. This would allegedly be the case where two or less network users have contracted capacity at the same network point. The Regulation explicitly provides that regulators shall not grant an authorisation to limit the amount of information made available by the TSO "where three or more network users have contracted capacity at the same point". This rule is referred to as the "three or more rule".

(241) On the basis of the information provided by the TSOs and the companies controlling considerable amounts of primary capacity on transit lines (the so-called "special capacity holders"), the inquiry looked at the extent to which these companies could try to claim, on the basis of the reservations reported to DG COMP for the years 2003-2005, that confidentiality issues would indeed prevent them making available to the market full information about technical capacity, contracted capacity, available capacity and used/unused capacity on transit lines[138]. Indeed, potential new entrants (amongst others) have expressed concerns at the extent to which confidentiality claims could hamper full transparency on accessible capacity on transit lines.

[138] In any case, the Gas Regulation states that national regulators' permission is required for any limitation of transparency, and they must take account of competition as well as confidentiality in deciding whether to give permission.

(242) Therefore, for each of the two main transit axes covered by the present stage of the inquiry, we investigated: first, if for each of the pipelines included in the axis, there were three or more primary capacity holders; and second, if for each of these pipelines, there were three or more primary and secondary[139] capacity holders[140]. It would appear that the argument of confidentiality is based on the number of actual users of the capacity rather than on the actual contractual situation.

(243) The results of this strand of analysis are represented below. With respect to the Benelux-Italy axis, the graph demonstrates that on an average of 80%[141] of the pipelines on this axis only one or two primary capacity holders control the entire capacity. A restrictive interpretation of the rules would mean that on the vast majority of the pipelines of this axis - which is crucial for developing market integration - only limited transparency should be provided on the capacities of the pipelines because disclosure of this information would reveal sensitive commercial information about the commercial behaviour of these one or two primary shippers. If one were to consider that both primary and secondary capacity reservations on the Benelux-Italy axis have to be taken into account - corresponding to the logic of the confidentiality argument[142] - the picture looks less bleak. However, even in such a scenario, an approximate 20% of transit lines could still endeavour to justify that transparency is not required. This would be on the basis that no secondary capacity whatsoever has been granted by the primary capacity owner(s).

(244) With respect to the East-West axis, Figure 30 demonstrates that on an average of 65% of the pipelines on this axis only one or two primary capacity holders control the entire capacity. This means that the amount of transparency could be limited on this axis. If one takes into account both primary and secondary capacity reservations, the picture does not change fundamentally. This can be explained by the fact that, as compared for instance with the Benelux-Italy axis, the amount of secondary capacity allocations is quite limited[143].

(245) On the vast majority of transit lines only one or two companies own primary capacity rights. These companies could try to make use of these rights – which they have often obtained under pre-liberalisation monopoly conditions – to argue that full application of transparency requirements would damage their commercial wholesale interests. Such an approach would mean that a high number of gas highways, which are crucial to develop competition and market integration in Europe, will not provide the transparency required.

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139 For the purpose of this analysis only, and without prejudice to any future interpretation of the provisions of the Gas regulation, DG COMP has only taken into account secondary capacity reservations with a duration longer than 3 months in within any given year.

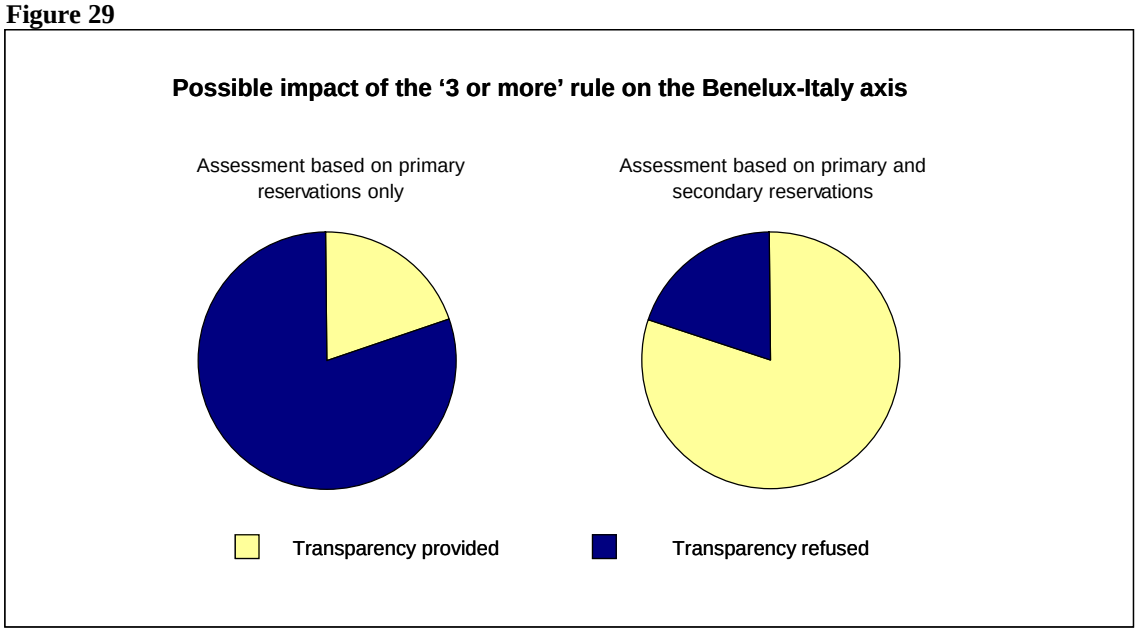
140 It must be highlighted that the confidentiality requirements –as they are laid down in the gas Regulation refer to transparency with respect to network points, whereas the information gathered in the context of the present inquiry concerns entire pipelines.

141 For this exercise, identical weight has been granted to all pipelines within the axis.

142 Secondary capacity allocations - even if they are not necessarily always reported by primary capacity holders to the TSO of a given pipeline - should logically be taken into account for the purpose of determining whether or not information about gas flows reveals sensitive commercial information about the behaviour of the shippers. Indeed, information about the usage of a particular pipeline, for instance, will only reveal commercially sensitive wholesale market information if the flows can, with sufficient certainty be attributed to a single shipper.

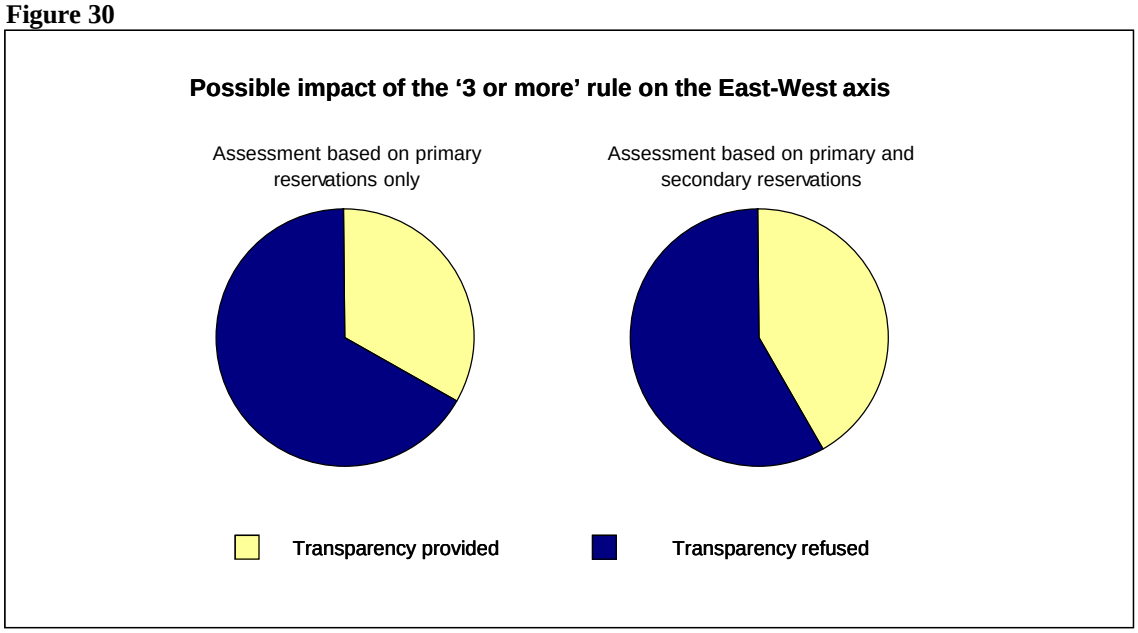
143 See above section 2.3.

Figure 29



Source: Energy Sector Inquiry 2005/2006

Figure 30



Source: Energy Sector Inquiry 2005/2006

(246) It should be highlighted that the analysis above has been undertaken without taking into account the extent to which the TSOs and/or primary capacity holders of the pipelines included in the axes have provided some transparency on a voluntary basis. However, a number of TSOs indicated that they do not publish information when there are less than three network users[144].

(247) New entrants criticised the fact that no information is published on available capacity when there are less than three network users.

144 When the regulators analysed how the second Guidelines of good practice were implemented, it appeared that not all TSOs who abstained from publishing information on the basis of that rule had actually applied for an authorisation from their national regulator. See the CEER "Monitoring report 2004 concerning compliance with the guidelines for good third party access practice to gas transmission systems", p. 100.

(248) If precise numerical information on available capacity is to be considered harmful for confidentiality when there are less than three network users, the publication of a range (e.g. between 30 and 40% of the capacity is available) should provide some transparency without allowing the capacity holders to determine the exact amount of capacity held by the other one. About 77% of the respondents to our transparency questions found that it would be useful (about 42%), important (about 26%) or indispensable (about 9%) to publish the number of capacity holders. This would create clarity on the justification of the lack of transparency.

II.4.3. Secondary trading - Unused capacity

(249) Article 5.3 of the Regulation foresees that in the event of contractual congestion, the TSO shall offer unused capacity on the primary market at least on a day-ahead and interruptible basis. Networks users shall also be entitled to put contracted capacity that they do not wish to use (or are unable to use) on the secondary market. There are no specific provisions on transparency regarding unused capacity[145]. Currently, information on unused capacity appears to be seldom published. Some TSO's explained that they have or will set up bulletin board where network users can offer unused capacity.

(250) The large majority of the respondents to our questionnaire (about 74%) indicated that information on aggregated unused capacity was either indispensable or important (see Table 6). This is also the case when there are fewer than three network users holding capacity (see Table 7). Many of those who responded that such information is not useful are incumbents.

Table 6

According to the respondents, information on aggregated unused capacity is:	
	% of total number records
Indispensable	40.4%
Important	34%
Useful	12.8%
Not useful	12.8%

Source: Energy Sector Inquiry 2005/2006

[145] The Regulation does require TSOs to publish information on interruptible capacity but this does not necessarily mean that all information on unused capacity is published.

Table 7

According to the respondents, information on aggregated unused capacity, when there are fewer than three network users holding capacity, is:	
	% of total number records
Indispensable	27.7%
Important	25.5%
Useful	25.5%
Not useful	21.3%

Source: Energy Sector Inquiry 2005/2006

(251) New entrants explained that the identification of capacity holders would facilitate secondary trading in capacity. The majority of users found that information on the identity of primary capacity holders was important (about 32%), useful (about 28%) or indispensable (15%). Information on the identity of secondary capacity holders is also considered useful by about 36% of the users, important by about 24% and indispensable by about 13% of them.

(252) Responses differed as to whether the identity of capacity holders, be it primary or secondary, should be revealed when there are fewer than three network users: those who answered that this information is not useful were mostly incumbents, whereas those who found the information useful, important or indispensable were new entrants (see Table 8 and Table 9).

Table 8

According to the respondents, information on identity of primary capacity holders, when there are fewer than three users holding capacity, is:	
	% of total number records
Useful	34%
Not useful	29.8%
Important	23.4%
Indispensable	12.8%

Source: Energy Sector Inquiry 2005/2006

Table 9

According to the respondents, information on the identity of secondary capacity holders, when there are fewer than three users holding capacity is:	
	% of total number records
Useful	38.4%
Not useful	31.9%
Important	19.1%
Indispensable	10.6%

Source: Energy Sector Inquiry 2005/2006

(253) The practical organisation of secondary trading of capacity is of course of major importance and its rules should be made public. This opinion is shared by all users. Information on how to transfer the title for capacity is indispensable for about 58% of the users or important for about 36% of them. Only 6% of the users found the information merely useful. The cost of the transfer of capacity title is an indispensable piece of information for about 60% of the users; it is important for about 38% and useful for about 2% of them.

II.4.4. Transparency regarding storage

(254) The importance of having access to information on technical and available storage capacity was underlined by the vast majority of users. Unsurprisingly, information on available storage capacity was considered indispensable by about 51% of the users and important by about 38%. About 2% of the users found the information merely useful and about 8% of them found it not useful. Information on maximum technical capacity was considered important by about 38% of the users, indispensable by about 34%, useful by 19% and not useful by about 8% of them. Information on contracted and unused storage capacity was also considered important by the users (see Table 10 and Table 11).

Table 10

According to the respondents, information on contracted/held storage capacity is:	
	% of total number records
Important	36.2%
Indispensable	29.8%
Useful	17%
Not useful	17%

Source: Energy Sector Inquiry 2005/2006

Table 11

According to the respondents, information on unused storage capacity is:	
	% of total number records
Important	40.4%
Indispensable	31.9%
Not useful	21.3%
Useful	6.4%

Source: Energy Sector Inquiry 2005/2006

(255) Storage users would like to receive detailed information[146]. The GGPSSO do not foresee to what time periods information on the storage capacity situation should refer to. Most respondents would like it to refer to daily periods (see Table 12). Those who answered "other" to the questions on the reference period for information on available storage indicated that information should be detailed in accordance with the type of storage (seasonal or peak-shaving) and refer to combinations of annual periods, seasonal periods, monthly periods, weekly periods and/or daily periods. According to about 38% of the users, forecasts of available capacity should cover the next three years (see Table 13). Some users indicated that forecasts of available storage capacity should go as far in the future as capacity can be booked (10 years forecasts if capacity can be booked for 10 years).

Table 12

According to the respondents, information on the storage capacity situation should refer to:	
	% of total number records
Daily periods	40.5%
Other - please specify below	25.5%
Hourly periods	17%
Weekly periods	10.6%
Monthly periods	6.4%

Source: Energy Sector Inquiry 2005/2006

146 The implementation of the GGPSSO has been monitored by ERGEG. The Final 2005 Report on Monitoring the implementation of the Guidelines for Good TPA Practice for Storage System Operators (GGPSSO) has been approved on 7 December 2005.

Table 13

According to the respondents, forecasts of available storage capacity should cover the next:	
	% of total number records
3 years	38.4%
year	19.1%
Other - please specify below	17%
2 years	14.9%
18 months	8.5%
6 months	2.1%

Source: Energy Sector Inquiry 2005/2006

Conclusion

Network users request more transparency on access to networks and transit capacity, as well as on storage. Users would like to see more detailed information than is currently provided for by the minimum requirements set by the Gas Directive and the Guidelines annexed to it. Notably, network users question the "three or more" rule and favour the enhancement of secondary trading by the publication of unused capacity. A number of new entrants would welcome the creation of a single transparent and integrated web platform providing information on available capacity for all transit pipelines.

II.5. Price issues

II.5.1. Prices in import contracts and on hubs

(256) Wholesale market prices are in most European markets dominated by the indexation mechanisms in contracts with producers. The sector inquiry has therefore focused on the indexation mechanisms actually used in these contracts. The investigation has established the proportions of gas prices indexed to inflation, crude oil, heavy fuel oil, light fuel oil, coal, electricity, spot gas or any other variable[147]. This preliminary report presents[148]:

- total indexation of long-term contracts in the EU
- indexation by region of the company producing gas
- indexation by region of the company importing gas

(257) Pricing on hubs is based on the supply and demand situation on each traded market. Although the pricing on the individual hubs has not been analysed in detail, a comparison is made of price levels on the three main trading hubs in the EU (NBP, Zeebrugge and the TTF-) with monthly prices paid by a sample of purchasers[149] under long term contracts over the period of January 2003 to December 2004. This gives a certain indication of general price levels paid under long-term contracts with those found in traded markets. It also highlights the price volatility of the open markets compared to that found in the long-term contracts.

(258) Finally, in order to compare the price levels and volatility of different types of long-term contracts, we compared the overall price level paid by a sample of gas purchasers under long-term agreements principally indexed to hub gas prices with prices paid under contracts indexed to oil and oil derivatives' prices.

II.5.2. Oil indexation of long-term gas contracts in the EU

(259) The preliminary findings of the inquiry confirm the widely known fact that prices in European long-term gas contracts are mainly linked to oil and oil derivatives.

(260) Since the continuing practice of linking gas to oil and oil-derivatives' prices is widespread in Europe, contract prices paid by different producers to different suppliers move in an almost identical manner through time. As a result, prices paid by purchasers under long-term contracts do not react smoothly (or at all) to changes in the supply and demand of gas markets. This effect is exacerbated by the fact that the indexation in long-term contracts is usually linked to variables calculated with trailing averages,

147 It should also be noted that a wider range of pricing arrangements are often included in the contracts, such as options to reduce off-take, summer discounts, seasonal prices and options to take a proportion of gas at a spot or fixed price.

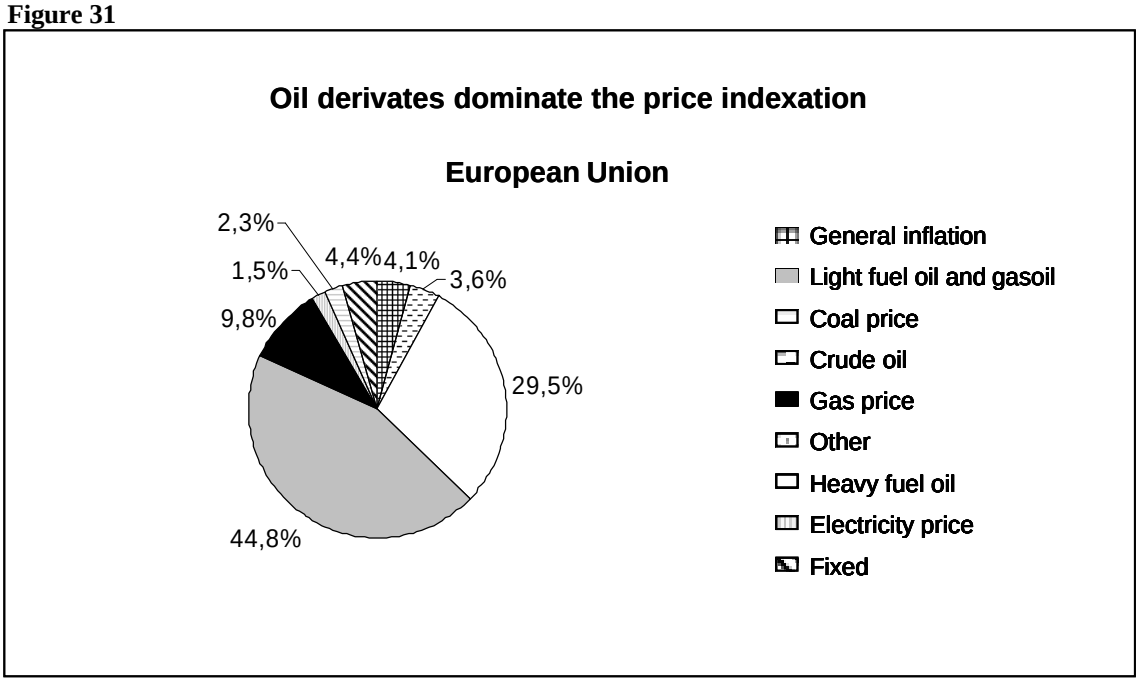
148 For the preliminary report, we have analysed oil price indexation in long term purchase agreements of thirty major producers and wholesalers of gas. Over 500 long term contracts (for our analysis, any contract of over 12 months was considered to be a long-term contract), representing around 400 billion cubic metres of contracted gas, were reviewed. These contracts include those between companies exporting gas to Europe and major EU gas wholesalers, as well as contracts between different EU gas wholesalers.

149 Our sample includes contracts from 11 major gas purchasers, buying over 270 billion cubic metres of gas per year.

further reducing response to price signals. No trend towards less distortive, more market based pricing mechanisms can be observed at this stage.

(261) The link between the purchase price of gas under long-term gas agreements and oil and oil-derivatives can be seen clearly in Figure 31 below. The graph shows the price indexation in our sample of long-term gas supply contracts. The analysis is based on data for calendar year 2004 and indicates the average volume-weighted indexation found in our sample of contracts.

Figure 31



Source: Energy Sector Inquiry 2005/2006

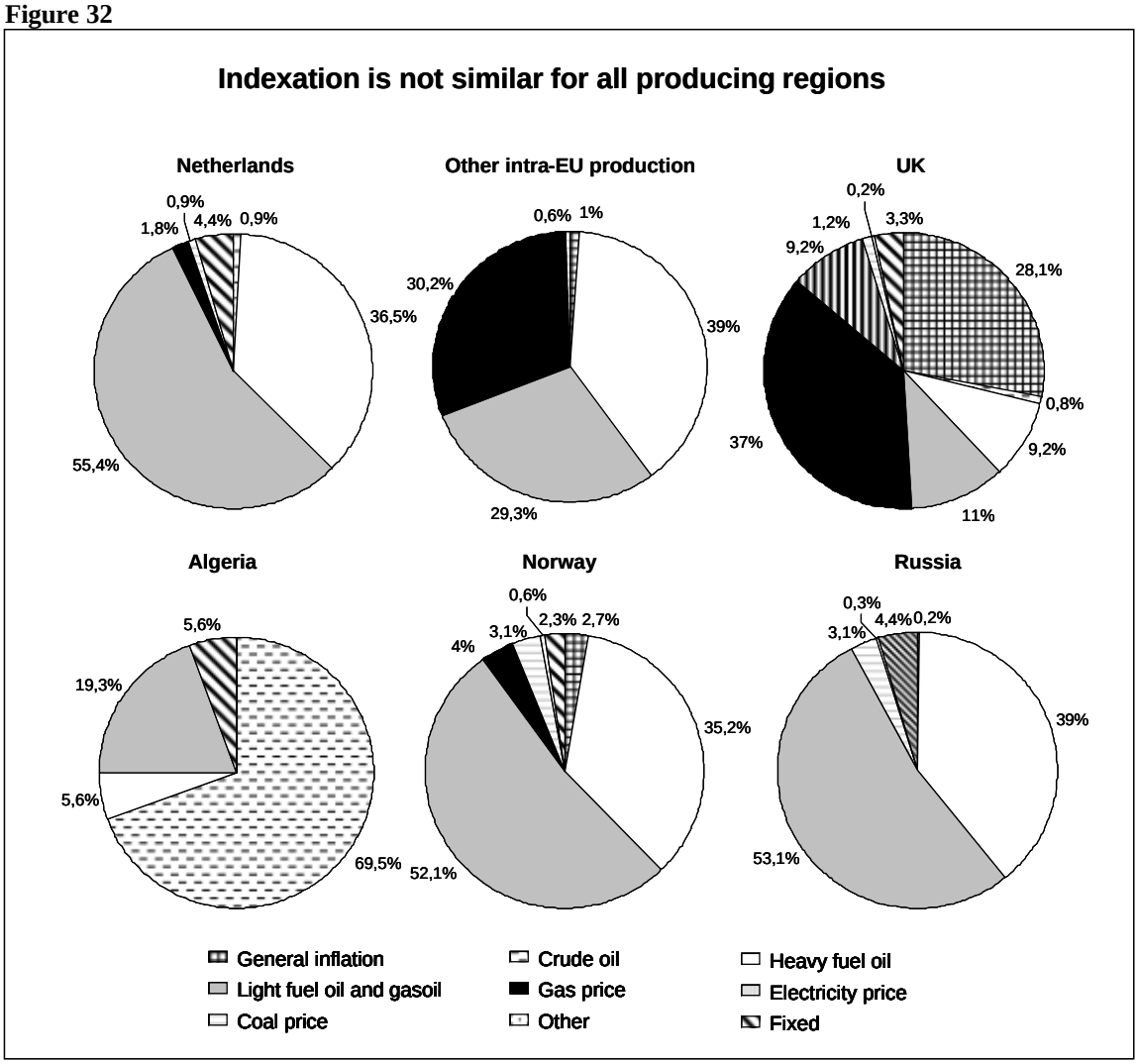
(262) The indexation arrangements in the pricing of gas under long-term contracts result in wholesale prices for gas that reflect the developments of the oil market[150], and in particular the market for oil derivatives such as heavy or light fuel oil (these account for around three quarters of gas price volatility). Given the similarity of the price indexation between most long-term contracts, the difference between the actual prices paid by different purchasers of gas under long term gas contracts will primarily reflect the difference in the underlying base prices (i.e., the original contract price).

(263) Following the general analysis of the indexation of long-term gas supply agreements in the EU, the sector inquiry has looked at indexation by source region[151].

150 There are often ceiling clauses on crude oil, light fuel oil and heavy fuel oil prices within gas contracts. In the contracts analysed in the inquiry, however, these do not apply to the full amount indexed within the contract but only to a specific part; for instance, if the contract includes 50% indexing to light fuel oil, the ceiling might only apply to 20% of the total light fuel oil element.

151 This comparison is based on data for calendar year 2004 and indicates the average volume weighted indexation found in our sample of contracts (excluding those for which it was impossible to determine the source of the gas).

Figure 32



Source: Energy Sector Inquiry 2005/2006

(264) It appears that long-term contracts from the Netherlands, Norway and Russia have almost identical indexation patterns, including over 80% of heavy and light fuel oil indexation. Because these three regions produce over 275 billion cubic metres of gas which is consumed in the EU, representing around 60% of the EU's natural gas needs, their indexation model will clearly have the most influence in determining the prices paid by European companies under long-term gas supply agreements.

(265) As to the other three regions, the inquiry found that Algerian gas was even more directly linked to oil prices, with almost 70% of changes to the price level being determined by crude oil prices, and an additional 25% by heavy and light fuel oil.

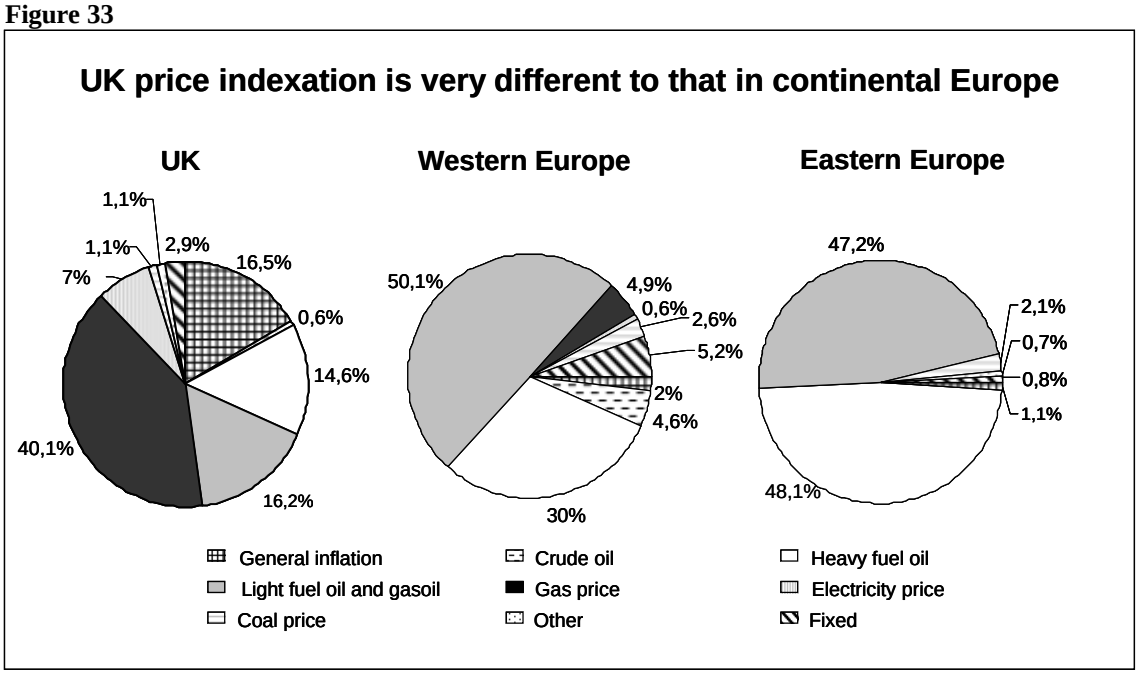
(266) Long-term gas sourced from UK fields has a very different indexation pattern than gas from the other regions, with the main determinants being hub gas prices (around 37%) and general inflation indices (just under 30%). Heavy and light fuel oil account for a further 20% of price indexation.

(267) Regarding other intra-EU gas production, whilst the 70% of heavy and light fuel oil price indexation is predictable, the rest of the price indexation is almost entirely made up of hub gas prices. One possible explanation for this would be that other intra-EU gas production was being sold mainly to UK wholesalers. However, this theory was not

corroborated by the available evidence. Another possibility is that the proximity of traded markets such as Zeebrugge and the TTF is starting to have an effect on the price indexation of long-term contracts for gas produced in surrounding areas. However, the price of long-term gas from the Netherlands, which has the TTF gas hub, is only 2% indexed to hub gas prices.

(268) The sector inquiry also looked at the indexation according to the region of the purchasing company. Long-term gas supply contracts were split into three groups depending on whether the buyer was from the UK, Western Europe[152] or Eastern Europe[153].

Figure 33



Source: Energy Sector Inquiry 2005/2006

(269) As can be seen above, the indexation present in long-term contracts for gas supply to continental Europe is very different to that found in the UK, where over 40% of the price volatility of gas under long-term contracts is determined by changes to the actual hub price of gas (usually the NBP or IPE prices). For Western Europe, changes in hub gas prices only account for around 5% of indexation. Within our sample of Eastern European long-term gas purchase contracts we were unable to find any contracts with indexation to hub gas prices.

(270) Conversely, the importance of heavy fuel oil and light fuel oil to determine the price level paid under long-term contracts is much higher in Western Europe (over 80% of indexation) and Eastern Europe (around 95% of indexation), than in the UK (around 30% of indexation).

(271) Apart from heavy fuel oil, light fuel oil and hub gas prices (in the UK's case), there are no other indices which have a major effect on prices of gas imported by European

[152] The Western Europe sample consists of long-term gas supply contracts to companies in Austria, Belgium, Denmark, France, Germany, Italy and the Netherlands.

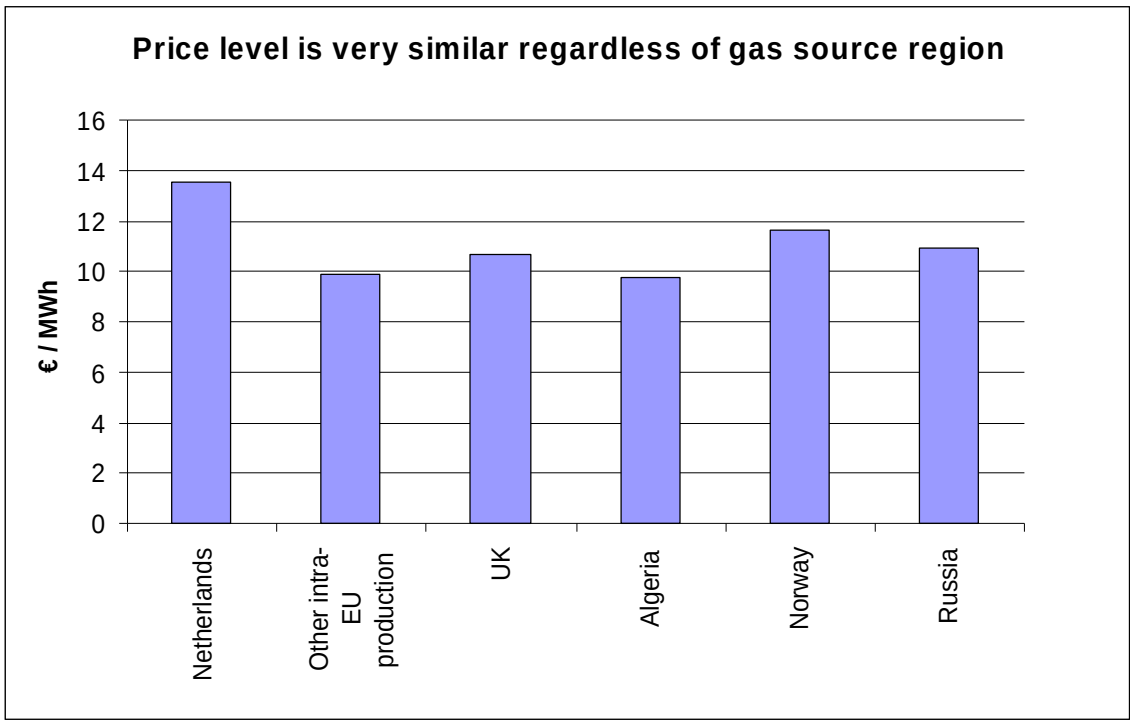
[153] The Eastern Europe sample consists of long-term gas supply contracts to companies in the Czech Republic, Hungary, Poland, Slovakia and Slovenia. Again, the analysis is based on data for calendar year 2004 and indicates the average volume weighted indexation found in our sample of contracts.

companies under long-term contracts. However, in the Western European market, crude oil and fixed price arrangements (each has around 5% of total indexation) also have a minor influence, as do, in the UK, electricity prices (around 7%) and general inflation indices (around 16%).

II.5.3. Price levels of long-term contracts

(272) In addition to the above analysis of indexation by source region of gas, we also examined the actual price levels of gas by region, in 2004[154]. Using the same sample as before, we calculated the average price paid during 2004 under each long-term gas agreement. We then calculated for each region the volume weighted average price.

Figure 34



Source: Energy Sector Inquiry 2005/2006

(273) As can be seen above, the average price level during 2004 for gas from long-term contracts varied between around 9.8€/MWh for Algeria and 12.8€/MWh for the Netherlands. All other regions settle between these two values, with most gas being purchased at levels between 10.5€/MWh and 11.5€/MWh.

(274) The fact that gas purchased from the Netherlands, Norway and Russia have similar price levels is not unexpected, seeing as they have comparable indexations patterns. However, it is surprising to find that gas purchased under long-term contracts from the UK is also being purchased at around the same price level when we have already seen that the UK displays distinct indexation patterns.

[154] Note that all our analyses of gas prices under long-term contracts only consider commodity prices and do not include any capacity charges.

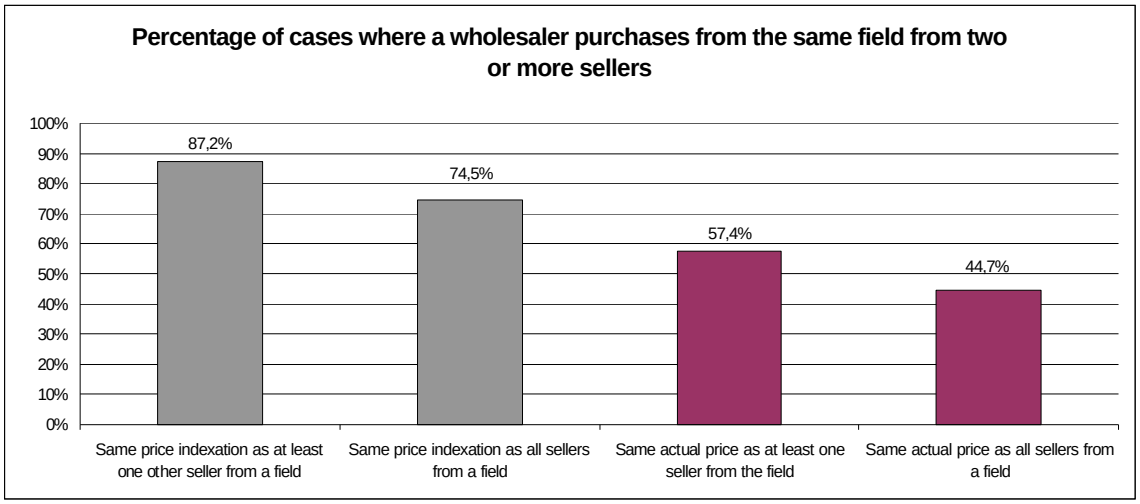
(275) The results for Algeria should be mitigated by the fact that the sample is smaller than that of the other regions[155], which reduces our confidence in this finding.

II.5.4. Price indexation and contractual arrangements for gas from the same field

(276) The enquiry has indicated a very strong similarity between the indexation in long term supply contracts of different producers selling from the same field. Most likely as a consequence of this, there is also a strong similarity between the actual prices paid by a wholesaler to several gas producers selling from the same field.

(277) The inquiry looked for all long-term gas purchase agreements involving deliveries of gas from the same field by more than one gas producer to the same gas wholesaler. We then analysed whether in these cases the price indexation formula included in the long-term contracts was the same for two or more of the contracts. Finally, we also looked at whether the actual price being paid by the purchaser to the producers was also the same. Figure 35, below, details our findings for calendar year 2004.

Figure 35



Source: Energy Sector Inquiry 2005/2006

(278) In almost 90% of cases where two or more producers are selling from the same field to the same wholesaler, the price indexation in the long-term contracts is the same. Furthermore, in almost two thirds of these cases, the same actual price is being paid by the wholesaler to the producers.

II.5.5. Prices: seasonality of hub prices

(279) In order to compare prices paid by wholesalers under long-term contracts with hub gas prices, the average volume weighted monthly price in a smaller sample of long-term gas supply contracts[156] was compared with the day ahead price of gas at the three principal hubs in Europe, the NBP, the Zeebrugge Hub and the TTF, over the period January 2003 to December 2004.

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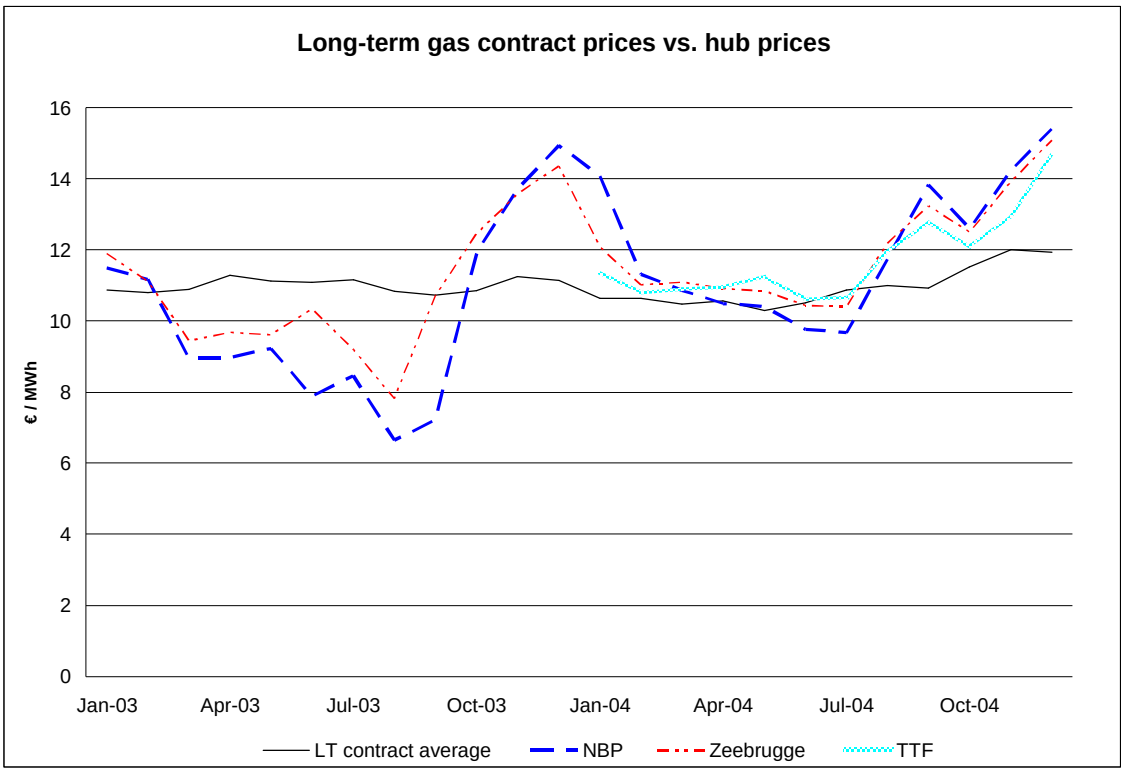
155 Since Spain was not included in the geographic scope of our inquiry, we do not have a very large sample of long-term gas contracts from Algeria.

156 We analysed the long-term gas supply contracts of 11 major gas purchasers, with a total purchased volume of 270 billion cubic metres.

Figure 36



Source: Energy Sector Inquiry 2005/2006

(280) It is evident from this comparison that long-term contracts are much less volatile than hub gas prices, as can be seen by the almost straight line in the graph above. This result is obvious in part because indexed formulae are often calculated using trailing averages of their components.

(281) Second, there is a seasonality to the hub gas prices which does not exist in long-term gas contracts as a whole. Whereas the hub gas price reflects a fall in demand in the summer months (April to September) and a rise in demand in the winter months (October to March), long-term gas prices remain constant throughout.

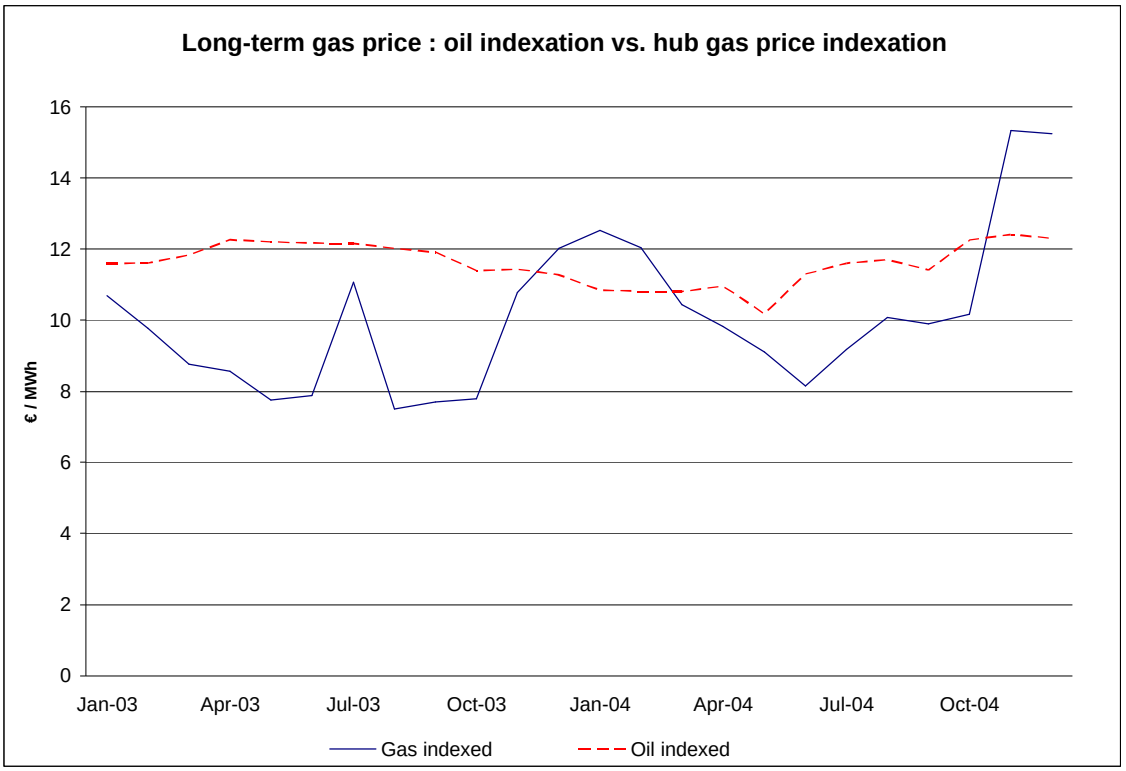
(282) This lack of reaction to demand signals means that the gas market does not react as it should to the signals coming from the seasonality of demand. For example, low summer prices should encourage companies to put more gas into storage during this period. This, in turn, should improve incentives for further investments in storage (as existing facilities would be used quicker) and transit pipelines (as capacity utilisation would be higher). However, gas sourced via long-term agreements does not provide these signals and as a result operators do not behave in a manner leading to the most economically efficient outcome.

(283) The inquiry analysis also compared the actual price paid under long-term contracts, depending on whether the majority of the price indexation was to oil derivatives or to gas prices[157]. We discarded contracts which had mixed indexation pricing or which were fully indexed to other variables.

[157] As for the previous graph, we took the sample of long-term contracts from 11 major gas purchasers, but this time we only kept those long-term contracts which were 50% or above indexed to either oil derivatives or hub gas

(284) We then calculated a volume weighted average monthly price for each month in the period January 2003 to December 2004, for long-term contracts mainly indexed to oil derivatives, and for long-term contracts mainly indexed to hub gas prices. The following graph, Figure 37, presents our findings.

Figure 37



Source: Energy Sector Inquiry 2005/2006

(285) The graph shows similar findings to those of our previous analysis. Long-term contracts indexed to oil are much less volatile than those indexed to hub gas prices. In this case, hub gas prices are below oil indexed prices for the majority of the analysis period, with the exception of the period November to February.

(286) The overall level of prices in oil indexed contracts was higher than in gas-indexed contracts for most of the period. However, the short periods when oil-indexation was cheaper were also the periods of highest volume (in winter). We suspect that, on a volume-weighted basis, there was no clear commercial advantage either way. However, the period of analysis is short relative to contracts durations, and developments subsequently have introduced considerable volalility (e.g. because of higher oil prices), so this situation may have evolved.

II.5.6. Interplay between a regulated and a "free market" price

(287) In a number of Member States, regulated retail prices co-exist with free market prices for some or all customers. A majority of Member States regulate prices to households and small businesses, while six set a regulated price that is available to all customers.

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prices. The total volume of contracts indexed to hub gas prices in our sample was 22 billion cubic metres. The total volume of contracts indexed to heavy or light fuel oil was 235 billion cubic metres.

However, the proportion of end-users that have stayed with the regulated tariff varies between countries.

(288) Regulated tariffs may have a negative effect on competition, particularly if they are set too low, so as to make cost-based competitive prices unattractive. The anti-competitive effect may however be greatly strengthened if incumbent suppliers are permitted to adjust the terms of a "tariff" service to suit a particular customer, as has been alleged by some respondents from France. A customer has also complained that competing suppliers in Spain are prevented by law from offering interruptible services and so cannot compete fully with the tariff, which includes an interruptible option.

Conclusions

Prices in most European long-term supply contracts are currently linked to heavy and light fuel oil.

Companies from the Netherlands, Norway and Russia, three of the major gas producers in Europe, all sell long-term gas with a price which is principally linked to heavy and light fuel oil. Companies from the UK and other intra-EU producing countries have a more mixed indexation in their pricing formulae, including an element of hub gas prices.

Whilst the price paid for gas under long-term contracts by companies from Western and Eastern Europe are principally indexed to oil derivatives, in the UK hub gas prices are the most important variable in determining the prices paid by companies purchasing gas under long-term supply contracts.

The overall price level of gas is similar for all gas producing regions. The interquartile range of long-term gas contract prices seems to be dependent on the amount of hub gas price indexation present in the contract.

In almost 90% of cases where two or more producers are selling from the same field to the same wholesaler, the price indexation in the long-term contracts is the same. Furthermore, in almost two thirds of these cases, the same actual price is being paid by the wholesaler to the producers.

Long term gas contracts exhibit a constant price throughout the period January 2003 to December 2004, whereas hub prices are much more volatile. In particular, hub prices change significantly from the summer to the winter, due to increased demand for energy. These price signals are not incorporated into the pricing mechanism of most long-term gas supply contracts.

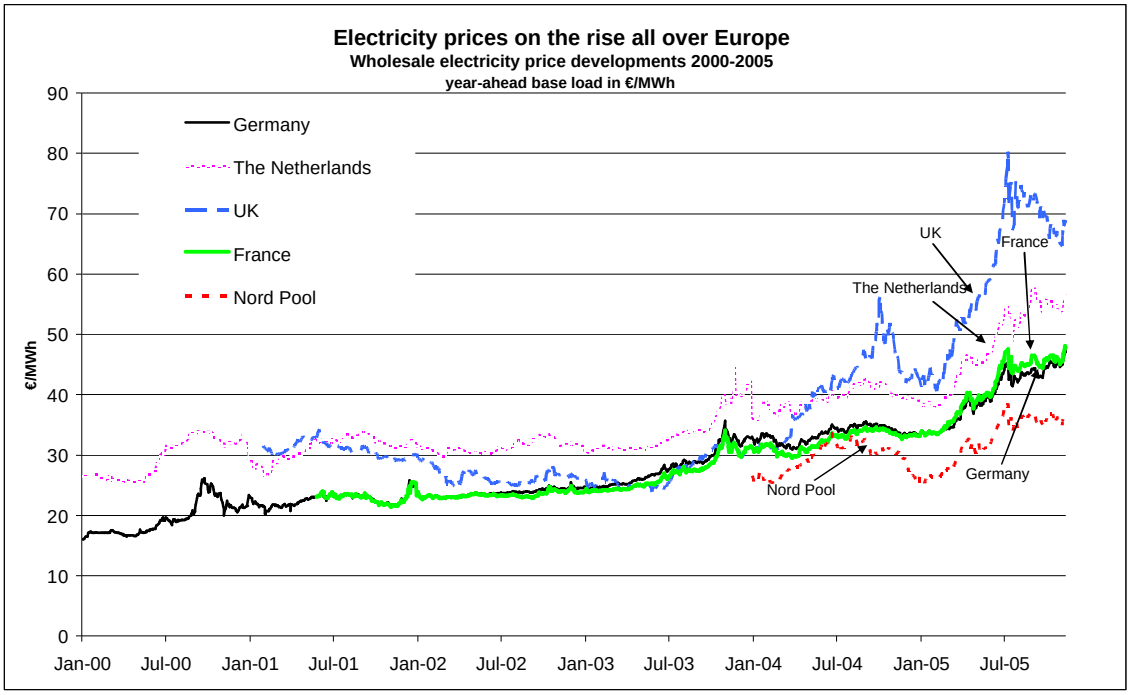
Long-term contracts with prices indexed mainly to gas also display seasonality, but on a volume-weighted basis their price level tends to be in line with that of long-term contracts indexed to oil, which do not display any seasonality or response to demand signals. This is because, contracts indexed to hub gas prices are more expensive during the peak winter months when most gas is consumed.

A number of Member States have some form of regulated prices which may have negative effects on competition, where these prices are set too low.

C. ELECTRICITY

I. Introduction

Figure 38



Source: information received within the scope of the sector inquiry from Argus Media, platts, and Nord Pool.

(289) Following market liberalisation, electricity wholesale prices were initially relatively stable[158].

(290) Around the summer of 2003, however, electricity wholesale prices started to rise on most markets. Not only did prices increase, they also diverged strongly between Member States suggesting a lack of market integration. Price rises have been strong especially since the beginning of 2005.

(291) As wholesale prices directly impact supply prices offered to final customers (especially to industrial users) in a number of Member States, their increase gave rise to wide-spread concerns about the overall functioning of the electricity markets. In addition many industrial consumers complained about the difficulties to secure competitive offers by different suppliers. These and other concerns expressed by market participants triggered the initiation of the sector inquiry into the European electricity sector.

158 Prices for certain end users even showed a downward trend after 2000.

I.1. Main market features

I.1.1. Overview

(292) During 2003, the countries today forming EU25 consumed 2605 TWh of electricity. This represents approximately 19.4 % of all final energy consumption in the EU[159]. The largest markets are, respectively, Germany, France, the UK, Italy and Spain. Less than 0.2% of the electricity required to meet this consumption was imported from outside the EU. In contrast to gas, the EU is thus essentially self-sufficient in the production of electricity and increasingly so as net imports decreased 81% over the period 1990-2003. Primarily fuels for electricity generation are of course often imported.

(293) Within the EU cross-border trading of electricity is more important than exchange with countries outside the EU. Luxembourg, Latvia and Hungary have net imports of respectively 62%, 51% and 22% of their national consumption. At the other end of the picture sit the Czech Republic and Estonia that have net exports amounting to 31% and 41% of their domestic consumption whereas Lithuania's net exports are with 106% even higher than its domestic consumption. In terms of volumes the largest net exporter of electricity is France, which exported 67 TWh in 2003, 4 times more electricity than the next largest net exporter, the Czech Republic whose exports however grew 23-fold since 1990. Poland is third in this ranking. Italy was by far the most important net importer of electricity, importing approximately three times as much as the Netherlands with Sweden coming as third largest net importer.

(294) A clear and important link between the functioning of the gas and electricity markets exists. The prices for gas significantly affect electricity price levels, since in many Member States, gas-fired power plants are responsible for setting the price level of electricity, in particular during peak hours. Moreover, a considerable and increasing quantity of gas is used in thermal power plants. During 2004, gas fired power plants in EU25 consumed approximately 4000 PJ GCV (gross calorific value) of gas corresponding to 22,1 % of the entire consumption of natural gas in the EU[160]. Hence, electricity generators rely heavily on competitive gas markets. Malfunctioning gas markets thus adversely affect the price levels of electricity.

I.1.2. Essential features of electricity markets

(295) The electricity industry chain involves five main activities: (1) the production or generation of electricity, (2) the transport of electricity on high voltage levels (transmission), (3) its transportation on low voltage levels (distribution), (4) the marketing of electricity to final customers (supply), and (5) the selling and buying of electricity on wholesale markets (trading). Sometimes services such as metering are mentioned as additional activity.

159 Eurogas, Annual Report 2004-2005, p. 27.

160 Eurogas, Annual Report 2004-2005, p. 28.

(296) Prior to liberalisation, vertically integrated companies executed these activities serving exclusively certain regions or even a whole country, and prices were regulated. This has profoundly changed with European-wide market opening. The electricity business was split up into regulated and competitive segments. Because transport activities were considered to be a natural monopoly, they remained regulated. However, generation, wholesale trading, and retail supply were opened to competition. Although a number of Member States retained however regulated supply tariffs.

(297) Like the gas industry the electricity sector is a network industry. Without access to the network customers cannot be reached. Third Party Access to the network is thus essential. The existing network is often a natural monopoly that cannot be duplicated in an economic manner and/or in a reasonably short time frame.

(298) An important feature of electricity is that it cannot be stored economically once produced. In order to ensure network stability electricity generation and consumption have to be in balance at all times. Electricity demand fluctuates significantly during the day and seasonally and has a very low price elasticity, i.e. price fluctuations do not give rise to large changes in electricity consumption.

(299) A specific feature of electricity production is that it can be produced by using a large variety of technologies and on the basis of different fuels (nuclear, hydro, coal, gas, renewables etc.). Cost structures have important implications for the price formation on short term electricity markets (concept of a marginal plant setting the price). The price formation mechanism also renders electricity markets vulnerable to the exercise of market power, be it through withdrawing generation capacity or be it by pricing above competitive levels at times when the generator is indispensable to meet demand (for further details see below chapter II.1).

(300) As electricity cannot be stored, balancing regimes exist to settle market participants' real-time imbalances resulting from discrepancies between scheduled and actual electricity demand. The present analysis, however, mainly concentrates on wholesale issues and does not systematically deal with balancing regimes, even if it is generally accepted that these markets are vulnerable to the exercise of market power. The balancing markets will be analysed in more detail in the final report.

(301) Various business models exist on electricity markets, ranging from stand-alone generators and independent supply companies to fully integrated utilities. In more recently liberalised Member States the vertically integrated company is predominant. In markets that were liberalised earlier, such as the UK and Nord Pool, business strategies seem to be somewhat more diverse. In the UK, apart from larger integrated companies, a number of independent generators with their own business strategies exist. Also on the Nordic market(s) consisting of Norway, Sweden, Finland and Denmark independent suppliers are relatively important.

(302) Typically, within fully integrated utilities, specialised affiliates are dedicated to the different activities, such as generation, trading, supply and network operations. Usually, all output of the generation affiliate is sold under intra-firm arrangements to the affiliated trading entity[161] which in turn manages the undertakings overall portfolio i.e. supplies the

[161] Important exceptions are Spain and to some extend Italy and the Nordic markets around Nord Pool. In all these cases there is an obligation or incentive to trade through the pool (see further I.3.4).

supply affiliate(s) and sells energy to or buys it from third parties through bespoke bilateral contracts or traded wholesale markets. Integrated companies can produce more or less electricity than is required for their own customer portfolio. The larger integrated companies often generate more electricity than they need for their final customers.

I.2. The regulatory framework

(303) EU energy policy pursues three objectives: (1) the creation of a competitive, integrated internal market (higher growth rates and increased competitiveness); (2) maintaining an adequate level of security of supply; and (3) increasing the effectiveness of environmental protection. This section provides a brief description of EU legislation aimed at achieving these objectives but focuses on the first objectives.

I.2.1. Liberalisation

I.2.1.1. The beginning of the liberalisation process:

(304) The first important community legislation aimed at liberalisation of the electricity sector was Directive 96/92/EC[162] ("First Electricity Directive"). The Directive removed legal monopolies by requiring Member States gradually to allow large electricity customers to choose their suppliers (concept of "eligibility"). It also obliged vertically integrated companies to grant third parties access to their transmission and distribution networks ("third party access"). Furthermore, for vertically integrated companies active in generation, transmission and supply it finally mandated a minimum level of separation of the network business from the other activities ("unbundling"). In a nutshell the Directive introduced the distinction between a regulated part of the market (network) and competitive parts of the market (generation and supply).

(305) The gradual market opening introduced by the First Electricity Directive resulted in significant differences between Member States regarding the level of market opening. The existence of negotiated third party access regimes, the limited level of unbundling obligations and the lack of an obligation to establish a national energy regulator were also viewed as obstacles to create competitive markets. To address these concerns, further measures were proposed by the Commission leading to the adoption of Directive 2003/54/EC[163] ("Second Electricity Directive") and Regulation (EC) No 1228/2003[164] ("Cross Border Electricity Trading Regulation").

I.2.1.2. The Second electricity Directive

Full market opening

(306) The Second Electricity Directive aimed at complete market opening by ensuring that all non-household electricity customers become eligible by 1 July 2004. This will be followed by the opening of the electricity markets for all household customers by 1 July

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162 Directive 96/92/EC of the European Parliament and of the Council of 19 December 1996 concerning common rules for the internal market in electricity (OJ 1997 L 27/20).

163 Directive 2003/54/EC European Parliament and of the Council of 26 June 2003 concerning common rules for the internal market in electricity and repealing Directive 96/92, (OJ 2003 L 176/37).

164 Regulation (EC) No 1228/2003 of the European Parliament and of the Council of 26 June 2003 on conditions for access to the network for cross-border exchanges of electricity, (OJ 2003 L 176/1).

2007[165]. This approach will remove the discrepancies in the level of market opening between Member States.

(307) Market opening by legislation does not, however, automatically lead to the introduction of competition in supply markets previously dominated by incumbent players. Whilst the Second Electricity Directive is silent on the issue, some Member States introduced (temporary) measures such as market share caps for incumbent operators to address concentration. In the UK the existing generation company was split up into competing undertakings, which facilitated the creation of competitive markets.

Regulated third party access and creation of regulators

(308) The Second Electricity Directive obliges Member States to introduce a "regulated third party access" regime under which third parties have a right to access the network in a non-discriminatory manner based on published tariffs. The Directive removes the possibility of negotiated third party access regimes, which were considered not to give the same results as regulated third party access regimes.

(309) In order to ensure efficient and constant supervision of fair network access, the Second Electricity Directive mandates the appointment of a national regulator that is independent from the electricity industry (but not necessarily independent from the Governments). The regulators must monitor the overall activities of the network companies, deal with complaints, and control network tariffs[166], a key element in creating competitive conditions.

(310) Some market participants raised concerns that the powers of regulators vary and that there are significant differences in market design. The regulators recognised the need for close cooperation – in particular for cross border trade – and formed an association for discussion and the development of common positions (CEER). They play an essential role when it comes to the creation of an efficient third party access regime. They also give advice to the Commission on legislative and other projects through ERGEG.[167]

Unbundling

(311) In order to limit further the risks of discrimination and cross subsidies associated with the existence of vertically integrated companies the Directive requires legal unbundling - in addition to accounting and management unbundling - between network activities (transmission and distribution) and all other activities. In practice this means that transmission and distribution system operators must be independent in their legal form, organisation and decision making (separate headquarters and separate board of directors). However a holding company is still entitled to approve the annual financial plan and to set global limits on the level of indebtness.

(312) The Directive permits the postponement of legal unbundling of distribution companies until 1 July 2007 and allows Member States to exempt them from the legal unbundling

165 Several Member States have already opened their markets for all electricity customers.

166 The regulator must approve the terms and conditions for network connection and tariffs, or at least the method of calculation the tariffs, prior to their entry into force. This power also exists with regard to balancing services.

167 Commission Decision 2003/796/EC of 11 November 2003 on establishing the European Regulators Group for Electricity and Gas (OJ 2003 L 296/34).

obligation altogether if the distribution companies serve less than 100,000 connected customers.

(313) The Directive does not impose that the network operator must own the network assets or that there is ownership unbundling[168] from the affiliated supply activities. Nevertheless, several Member States have introduced ownership unbundling for transmission systems arguing that only this form of unbundling removes the incentives in vertically integrated companies for the transmission branch to favour the supply branch.

(314) The issue of structural integration between generation and retail is also not addressed in the Second Electricity Directive. The same applies to long term power purchase agreements, which can also lead to a reduction of liquidity of wholesale markets. This form of vertical integration can be subject to EC competition law (antitrust rules or state aid rules).

Conclusion

(315) The Second Electricity Directive has significantly contributed to the creation of a common electricity market provided that all Member States properly implement it – not only in form, but also in spirit. The Commission is actively pursuing the lack of adequate implementation of the Directive in certain Member States.

(316) On the other hand it is worth recalling that the Directive only contains minimum requirements, leading to different market designs between Member States. Some market participants raised concerns in this respect as the differences in market design can amount to entry barriers and undermine the level playing field for operators located in different Member States.

I.2.1.3. The Cross Border Electricity Trading Regulation

(317) The legislative measures for electricity adopted in 2003 included a second element: the Cross Border Electricity Trading Regulation. This Regulation addresses issues relating to cross-border trading in electricity, such as harmonised principles for payments between transmission system operators and for tariff setting as well as congestion management and the allocation of cross border capacity. The Regulation entitles the Commission to adopt and amend legally binding guidelines for more detailed rules.

(318) The Regulation's rules on congestion management[169] are of central importance, as mechanisms to allocate congested interconnection capacity play a crucial role in market integration[170]. The Regulation requires that congestion problems on interconnectors be addressed through non-discriminatory, market-based solutions. The Guidelines on

168 Ownership unbundling means that a supply company is prevented from owning an entity that operates a network.

169 Regulators are also given tasks under the Second Electricity Directive regarding cross-border electricity trading as they must monitor rules on the allocation of interconnector capacity in cooperation with the other regulators of Member States connected by the interconnector.

170 Congestion problems are aggravated by long term contracts for capacity reservations on interconnectors which were concluded before liberalisation. In a recent judgment (C-17/03, Vereiniging voor Energie, Milieu an Water) the ECJ stated that preferential access based on such contracts amounted to discrimination prohibited by the first Electricity Directive and was, as such, contrary to EC law. The Member States concerned in this case had not applied under Article 24 of the First Electricity Directive for a derogation from relevant provisions of that Directive.

congestion management[171] are currently being amended, and the new Guidelines will probably identify both explicit and implicit auctions as methods complying with this requirement[172]. The preliminary report's chapter on market integration examines these methods in more detail.

(319) The Regulation also contains provisions to allow private investment in interconnectors ("merchant lines"), as the existence of sufficient interconnector capacity is essential for the development of an integrated market. To this end, new interconnectors (DC lines only) may be exempted from the rules on how revenues from capacity allocation are spent as well as from provisions relating to non-discriminatory network access. For the exemption to be granted, it must be shown that the interconnector enhances competition and that the investment would not take place in the absence of an exemption. Whereas in the gas sector several applications for an exemption of a similar type were notified to the Commission, the Commission has so far received only one notification regarding an exemption for an electricity interconnnector (a second is under preparation).

I.2.2. Security of Supply

(320) EU energy policy also aims at maintaining a high level of supply security. Security of supply comprises of two elements: the need for system security as well as the need for adequate supply of electricity in the medium and the long term. Whilst the issue of security of supply is already addressed in the Second Electricity Directive and in the Cross Border Electricity Trading Regulation, in 2003 the Commission made a proposal for a comprehensive set of rules regarding this matter.

(321) The recently adopted Directive on Electricity Security of Supply and Infrastructure (2005/89/EC) requires Member States to ensure that an appropriate level of network security is maintained[173] and that stable and transparent market rules are in place regarding any action taken to balance supply and demand. In addition, networks must set performance objectives and the regulatory framework must provide appropriate signals for network development and facilitate appropriate network maintenance. The Directive will enter into force in December 2007.

I.2.3. Environmental protection

(322) Last but not least EU energy policy must take into account the need to improve environmental protection and sustainable development. To that end, and to help comply with the Kyoto Protocol, the EU has adopted a number of important legislative measures.

(323) Pursuant to Directive 2003/87/EC[174] (the "Emissions Trading Directive"), Member States must ensure that all plants with a rated thermal input exceeding 20MW emitting CO2

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171 Guidelines on the management and allocation of available transfer capacity of interconnections between national systems, (OJ 2003 L 176/9).

172 In an explicit auction, market participants bid for available interconnector capacity which is purchased separately from the electricity that is the subject of the transaction. In an implicit auction, interconnector capacity would be made available to the power exchanges, and a market clearing procedure would determine the most efficient use of such capacity. Explicit auctions are already provided for in the existing Guidelines.

173 Operational security rules for TSOs on continental Europe are also described in the Union for the Co-ordination of Transmission of Electricity (UCTE)'s Operation Handbook

174 Directive 2003/87/EC of the European Parliament and of the Council 13 October 2003 establishing a scheme for greenhouse gas emission allowance trading within the Community and amending Council Directive 96/61/EC, (OJ 2003 L 275/32).

only operate if they have greenhouse gas permit. Member States decide periodically in national allocation plans about the number of allowances allocated for free to each plant. The Directive established the European Union Greenhouse Gas Emission Trading Scheme (EU ETS), which, since 1 January 2005, serves as a trading framework for emission allowances. Plants emitting below the level of allowances allocated can sell their excess, and those exceeding their allocation must purchase additional allowances. The ETS and in particular the alleged effects on electricity prices is discussed below in the chapter on price formation.

(324) Directive 2001/77/EC[175] (the "Renewable Electricity Directive") is an important step in the development of power generation from renewable sources, most of which would otherwise not be attractive for investment. It mandates that Member States set national targets to meet the Community target of increasing the share of electricity consumption from renewable sources to 22% by 2010[176]. It also encourages Member States to apply various support mechanisms[177] in favour of green electricity production. The Directive permits Member States to require priority access to the grid for producers of green electricity and mandates that priority is given to green electricity when dispatching electricity. Directive 2004/8/EC on the promotion of cogeneration[178] contains provisions on network access for such electricity similar to those in the Renewable Electricity Directive. Electricity produced from a renewable source or from cogeneration is also promoted by the Community guidelines on State aid for environmental protection[179], which explains the conditions under which such State aid will be deemed to be compatible with the common market. Some market participants claimed that electricity produced from renewable sources lead to new challenges for network operations.

(325) In 2003 the Commission proposed a Directive on energy end-use efficiency and energy services (COM (2003) 739 final) to address environmental concerns relating to energy consumption. According to the Draft Directive, Member States would be required to achieve an overall national indicative energy savings target of 9% for the ninth year following the entry into force of the Directive by measures improving energy efficiency. It is expected that the Directive is adopted in the not too distant future.

175 Directive 2001/77/EC of the European Parliament and of the Council of 27 September 2001 on the promotion of electricity produced from renewable energy sources in the internal electricity market (OJ 2001 L 283/33).

176 An analysis of progress reports of Member States shows that measures currently in place will probably be insufficient to achieve this target. Report on the Green Paper on Energy, p. 7.

177 These support schemes include green certificates, feed-in tariffs, tendering and tax incentives.

178 Directive 2004/8/EC of the European Parliament and of the Council of 11 February 2004 on the promotion of cogeneration based on useful heat demand in the internal electricity market and amending Directive 92/42/EEC (OJ 2004 L52/50).

179 OJ 2001 C 37/3.

I.3. Electricity wholesale markets

(326) Wholesale trading, which is the main focus of this report, is the selling and buying of electricity in bulk. On wholesale markets generators can sell their output and suppliers can source the energy they need to supply end consumers. Trust in properly functioning wholesale mechanisms and the prices formed on these markets is of the utmost importance, not just for generators and suppliers, but also for electricity consumers whose energy bills are strongly affected by the prices formed on these markets.

I.3.1. The benefits of competitive wholesale markets

(327) Competitive wholesale markets generate efficiencies in the overall performance of the electricity sector by providing price signals to market participants[180]. In particular, the main benefits of efficient wholesale markets are:

1. **effective competition in generation and retail**, because competitive wholesale markets reduce the entry barriers for independent generators and retailers. Otherwise new entrants might be obliged to enter both the generation and the retail markets at the same time as a vertically integrated supplier;

2. **efficient investment and improved security of supply**, because competitive wholesale markets provide price signals on demand and supply and so encourage new investment when necessary and give the signals to potential investors on the type of investment (e.g. base-load or peak) that is most required in the market;

3. **efficient operation**, because well-functioning wholesale markets will give signals to the market to dispatch low cost plant and to plan maintenance at times with the lowest demand. On the other hand price signals can encourage flexible customers to reduce their demand at times of peak consumption etc;

4. **efficient risk management**, because wholesale markets allow suppliers and consumers to fine tune their portfolio of electricity at a minimum volume and price risk; and,

5. **efficient use and expansion of transmission infrastructure**, because competitive wholesale markets provide the price signals necessary for the TSO and regulatory agencies to identify when market participants should transmit energy from one zone to another and furthermore to identify when and where additional interconnection capacity would be cost effective.

[180] See for example, EFET Position Paper: Transparency and Availability of Information in Continental European Wholesale Electricity Markets, July 2003.

I.3.2. Basic features of wholesale markets

I.3.2.1. Wholesale market participants

(328) There are different reasons to be active on electricity wholesale markets. Generally speaking market participants can be divided in two groups: players with inherent physical positions (generators and suppliers) and participants without inherent physical positions (traders).

(329) The interest for generators to trade stems mainly from the need to sell their generation output and optimise the operation of their generation portfolio. In a number of Member States this selling is predominantly executed on forward markets, whereas optimisation of the power plant portfolio is carried out on spot markets i.e. day-ahead or within-the-day markets. By selling electricity forward, generators hedge themselves against spot price fluctuations.

(330) Retailers, on the other hand, trade on wholesale markets to procure the electricity needed for their customers. The vast majority of the electricity is contracted forward in a number of Member States. By doing so, retailers limit their risk exposure that would arise from changes in spot prices.

(331) In comparison to generators and retailers, (financial) traders buy and sell to exploit price differences e.g. between two geographical areas (arbitrage). Traders also take speculative positions, aggregate and disaggregate purchases and sales over different time horizons or locations thus offering to others the chance to manage their risks.

(332) Our analysis shows that larger electricity companies take part in active trading for all the reasons mentioned above. They do not just sell their surplus generation or cover their supply commitments but engage in arbitrage deals or take speculative positions. On the other hand smaller companies tend to be active on the wholesale market only to optimise their physical portfolios.

I.3.2.2. Market places

(333) The inquiry has looked at wholesale trading in standardised contracts which takes place on two different marketplaces. Transactions are either executed via power exchanges or over the counter (‘OTC’).

(334) Power exchanges are organised marketplaces. Market participants transact anonymously using the exchange as central counterpart. Trades are cleared by the power exchange or its appointed clearing house, thereby greatly reducing counterparty risk, i.e. the risk that a party defaults on its contractual obligations. Power exchanges that have gained some significance include Nord Pool, EEX in Germany, APX in Holland, Powernext in France, OMEL in Spain and GME in Italy.

(335) Unlike exchange trading, OTC transactions do not per se involve organised marketplaces. Rules governing the trade are typically derived from practice and based on industry

agreements.[181] Transactions are carried out bilaterally and counterparty risk is born by the market participants. Increasingly, transactions on traded OTC electricity markets are cleared by third parties, such as brokers or power exchanges, thus helping liquidity develop. Most standard transactions are facilitated by brokers' telephone or screen-based services. The main brokers included in our inquiry are GFI, ICAP, Prebon, Spectron and TFS.

(336) Apart from standardised exchange and OTC trading there are also bespoke bilateral transactions. These deals can be very different in terms of products delivered or services included ranging from back-up agreements to full supply contracts including volume flexibilities and balancing energy.

Table 14

Selected features of power exchange and OTC markets

	Power Exchange	OTC
anonymity of trading	yes	no
counterparty	central counterpart	bilateral trading
counterparty risk	no	yes (if not cleared)
spot trading	single auction	continuous trading
price and volume transparency	directly	indirectly

Source: Energy Sector Inquiry 2005/2006

I.3.2.3. Traded products, time horizons

(337) Depending on the delivery period, bulk electricity can be traded on spot or forward markets. Spot markets are mainly day-ahead markets on which electricity is traded one day before physical delivery takes place. On forward markets, power is traded for delivery further ahead in time.

(338) Typical spot products on continental markets are single hours or groups of hours, whereas forward products include weekly, monthly, quarterly and yearly products. Forward electricity can either be traded as a 'base' or a 'peak' contract. The term 'base' implies a continuous delivery throughout the delivery period (e.g. a month), whereas 'peak' typically only involves a delivery on business days from 08:00 till 20:00. The definitions and contract specifications may differ between countries.

(339) Electricity for spot and forward delivery can be traded on both power exchanges and OTC markets. Standardised forward contracts traded on exchanges are called futures.[182] Contract specifications of exchange traded and OTC products are in practice very similar or identical allowing for efficient arbitrage. To illustrate this, Table 15 shows the different spot and forward/futures contracts which can be traded on Powernext, the French power exchange, and the French OTC market.

[181] e.g. 'Standard Electricity Contract' of the European Federation of Energy Traders.

[182] Depending on the contract specification of the power exchange in question, futures contracts can be settled physically or financially. The later means that during the delivery period of the contract no physical electricity delivery takes place but a difference is paid between the prevailing spot price and the contract settlement price.

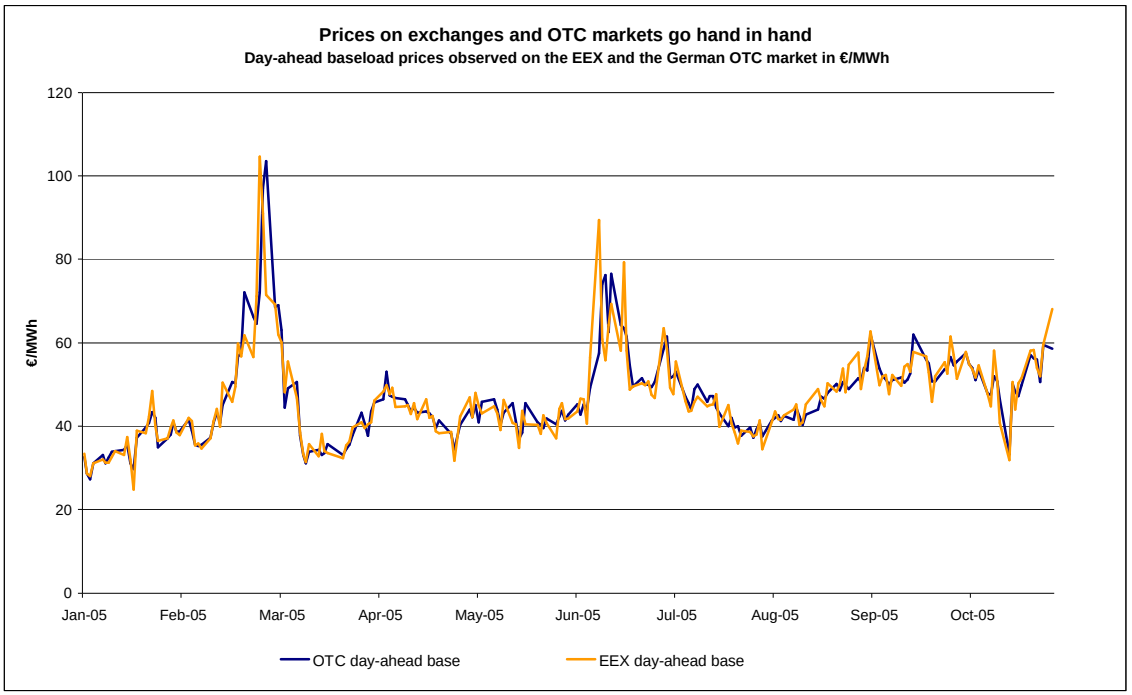
Table 15

Traded contracts on the French electricity wholesale market		
	Powernext	**French OTC market as assessed by platts**
day-ahead	24 single hours and 11 different blocks of hours	base & peak
week-end	-	base
week-ahead	-	base & peak
months	3 consecutive months, base & peak	3 consecutive months, base & peak
quarters	4 consecutive quarters, base & peak	2 consecutive quarters, base & peak
years	3 consecutive years, base & peak	2 consecutive years, base & peak

Source: platts, Powernext

(340) As a result of continuous arbitrage, prices of identical products traded on different marketplaces (i.e. on power exchanges or OTC markets) go hand in hand. Indeed, Figure 39 shows that, for instance, prices for day-ahead baseload delivery observed on the EEX, the German power exchange, and the German OTC market are closely correlated both in terms of development and levels.

Figure 39



Source: EEX, Argus Media

I.3.2.4. Price formation on short term markets

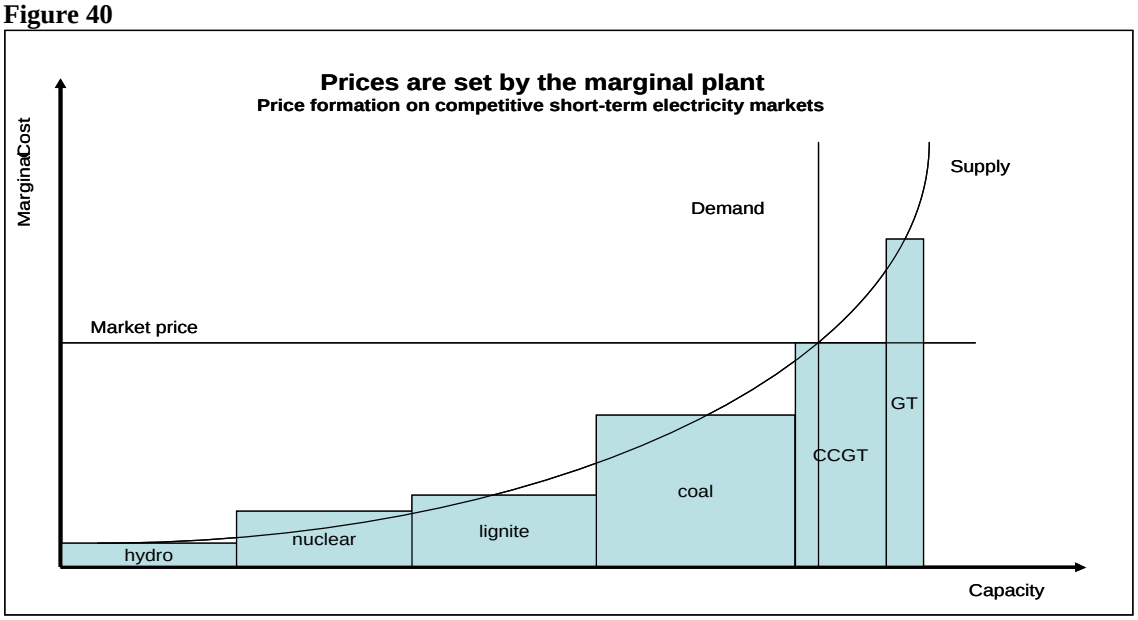
(341) As noted above electricity can be produced in many ways using a variety of fuels and applying different technologies. This diversity also results in different cost structures. Generation technologies that use low-cost fuels (e.g. nuclear fuel, lignite) often require relatively large capital investments[183]. On the other hand, generation technologies requiring relatively expensive fuels (e.g. gas turbines) have relatively low fixed costs. These differences in cost structures have important implications for the price formation on short-term electricity markets.

183 Including run-of-river plants that do not use fuels to generate electricity

(342) On competitive short term markets and in absence of generation capacity constraints, economic theory would suggest that prices are set by the short run marginal cost ('SRMC') of the plant producing the last unit of electricity required to meet demand. SRMC are mainly the fuel costs and some other, less substantial, variable production costs. The last, or marginal, unit needed to meet demand is also the one with the highest SRMC of all units running at a given point in time. The logic of this process ensures that only those power plants operate that have the lowest SRMC among all generation units available to operate[184]. As a consequence, it can be expected that nuclear or lignite fired power plants will be dispatched continuously and serve as base load units. For marginal and therefore price setting units – depending on the market in question – it would be expected that they are fuelled by natural gas or black coal.[185]

(343) In this respect it is important to underline that the SRMC of the price setting unit determines not only the revenues of the owner of the marginal plant, but also of all other operators with e.g. nuclear, lignite or run-of-river units. Whilst their marginal costs are often significantly lower it is generally argued that they need a higher price than the marginal costs to recover the higher fixed costs associated with base load generation. Figure 40 also explains this concept graphically using a schematic 'merit order'.[186]

Figure 40



Source: Energy Sector Inquiry 2005/2006
Note: This graph is only an abstract representation. It does not necessarily reflect actual cost relations between different types of generation and equally does not include the value of CO2 allowances

184 This price mechanism only applies for short-term markets and not for the price formation on forward markets.

185 In some markets, such as the Nordic market, hydro storage plants might often be on the margin. The SRMC of these plants is based on the alternative value of the water in storage

186 The term 'merit order' refers to the sequence of generating units according to their SRMC.

(344) Spot prices on power exchanges are usually set in single auctions, separately for 24 individual hours.[187] Each market participant hands in price-quantity pairs for its selling and purchasing plans from which the exchange derives aggregate supply and demand curves. The market price and the corresponding clearing quantity are then set as a result of the matching process. Prices and volumes for the individual hours are publicised and made available by the power exchange. In this respect it is important to note that generators may decide to offer electricity from their plants also at price levels other than SRMC.

(345) In comparison, on OTC markets spot transactions are carried out in continuous trading. Bids and offers are communicated to the market by brokers, usually by entering them into brokers' internet-based trading platforms. Since trading is done by using a number of brokers or directly between parties, prices are not directly known to all participants. Price discovery is the work of price reporters, such as Argus or platts, which assess the market based on market participants' voluntary reporting of prices and traded volumes. A variety of these assessments and indices are sold to the wider public.

I.3.2.5. Price formation on forward markets

(346) Wholesale electricity prices are influenced by both supply and demand factors. However, factors influencing prices in the short run can be somewhat different from those in the long run. According to the answers of market participants in the sector inquiry, short term prices are mainly influenced by plant availability, fuel prices, precipitation, wind speed, interconnector availability, temperature and, since 2005, CO2 prices. Prices in the long run are predominantly determined by forward fuel prices, (new) generation capacity (or capacity retirement), water reservoir levels, weather trends, interconnector capacities, CO2 prices and economic growth.

(347) Whereas forward prices are largely influenced by supply-demand fundamentals that are expected to prevail in the future, spot prices are determined by the out-turn of these fundamentals. In this way forward prices can give an indication of the overall market expectation about future spot prices[188]. The role that individual expectations play in the setting of forward prices also implies that no explicit price benchmark (similarly to the one that was introduced in the Chapter I.3.2.4. for short-term markets) can be used to determine what the price of a certain forward product should be at a given point in time.

(348) In addition to this forward prices are not only influenced by the expected supply-demand balance. Sellers and buyers engage in forward contracts because they prefer price certainty to unknown spot prices in the future. Therefore forward prices will also include a risk element. Depending on whether buyers or sellers attach a higher value to price certainty this will be a premium or a discount – though in practice it appears often be a premium. The buyer's willingness to pay for price certainty depends – amongst other factors – on the volatility of spot prices. The more volatile spot prices are, the less buyers will be likely to rely on spot transactions and turn to forward markets instead.

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187 On most of the power exchanges different blocks of hours can be traded as well.

188 This does not mean of course that forward prices should at any time necessarily be equal to out-turn prices. Expectations as regards future fundamentals might be very different from their outcome.

(349) Therefore, generators with market power on spot markets have ample opportunities to influence forward prices indirectly. For example dominant operators could withhold a part of their generation capacity. This would not only raise spot prices but also change market participants' expectations of the development of this fundamental supply side factor resulting in higher forward prices. Generators could also increase the volatility of spot prices (without changing the overall level of prices), which would increase the value of hedging them in advance on the forward market and may raise the premium of forward prices over expected spot prices. While pursuing these strategies might be costly for generators, this could be outweighed by higher revenues on their total portfolio.

I.3.3. Wholesale market outcome and end-customer pricing

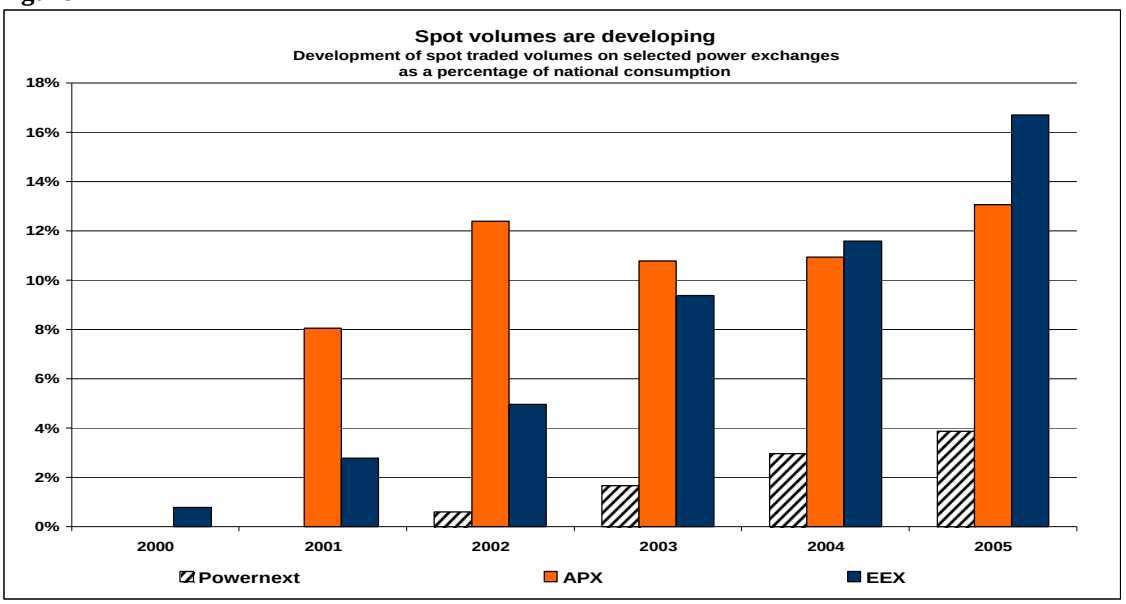
(350) Especially in countries where generators sell a considerable part of their generation months or even years ahead of actual delivery and where traded forward markets exist (e.g. Germany, France, UK, The Netherlands); it is a common practice for suppliers to offer fixed price supply contracts to their large business or industrial customers. Fixed price contracts also appear to reflect industrial energy users' preference.

(351) The inquiry shows that suppliers have fairly similar ways to set prices for fixed term contracts. The prospective consumers' hourly consumption over the contract duration (most often 1 to 2 years) is estimated on the basis of past consumption patterns assuming that these are indicative for future ones. The cost to serve this expected consumption is assessed with the help of an hourly forward price curve derived from relevant forward wholesale price quotations prevailing at the time the offer is prepared. The result is the actual cost of covering forward the customer's consumption on the wholesale market. The final price quoted to the customer will in addition contain other cost components such as expected cost of balancing or the supplier's own margin.

(352) The described pricing practice applies irrespective of whether the customer will in reality be supplied from the supplier's own generation portfolio or covered by electricity purchases on the market. Business units (i.e. generation and supply units) of integrated electricity companies generally act as profit centres and their performance is measured against the best alternative opportunity on the market.

I.3.4. Traded volumes on spot markets

Figure 41



Source: Powernext, APX, EEX

(353) Figure 41 shows the development of traded spot volumes relative to the consumption in the relevant geographical area for some selected markets. Over the whole period, traded volumes developed positively.[189]

Table 16

Spot traded volumes as a percentage of national electricity consumption (June 2004 - May 2005)

	Power exchanges	OTC brokered
OMEL - Spain	84,02%	negligible
GME - Italy	43,67%	n.a.
Nord Pool - Nordic region	42,82%	n.a.
EEX -Germany	13,24%	5,40%
APX - The Netherlands	11,88%	5,90%
Belgium	no power exchange	0,04%
Powernext - France	3,37%	1,50%
EXAA - Austria	2,96%	n.a.
UKPX - UK	2,17%	8,60%
Pol PX - Poland	1,28%	n.a.

Source: exchanges' and brokers' data
Note: This table does not contain an exhaustive list of all power exchanges in Europe. OTC brokered numbers refer to volumes reported to us by major energy brokers.

(354) Table 16 shows spot volumes traded on power exchanges and on OTC markets relative to electricity consumption in the relevant geographical area. It is evident that large differences exist between geographical areas. These differences are partly the result of diverging national wholesale market frameworks. According to their design, power exchanges can be divided into two broad groups. In the first group members of power exchanges have some kind of need or incentive to trade via the exchange (OMEL, GME,

189 Some respondents noted that the (temporary) decrease in traded spot volumes on APX during 2003, was to be ascribed to the distrust of market participant after strong price spikes had occurred when some power plants shut down due to cooling water constraints in the summer

Nord Pool).[190] In the second group exchange members have no such incentives. In this group EEX and APX saw significantly higher spot volumes traded than Powernext, EXAA, Pol PX and the UKPX. For reasons mentioned above, a direct comparison between the two groups of exchanges is not reasonable.

(355) From this table it also emerges that traded spot volumes on exchanges are larger than brokered spot markets in most of the countries we have examined. Thus market results on power exchanges seem to be setting the pace for the overall traded spot market.

I.3.5. Traded volumes on forward markets

(356) As can be seen from Table 17, total traded volumes in standardised forward contracts show large variations among countries, suggesting varying degrees of market development. Yet again, market design appears to be an important factor. Forward trading in Spain is insignificant, reflecting the de facto mandatory nature of the pool system on OMEL[191]. In contrast, the Dutch and German OTC forward markets traded by far the highest volumes (relative to consumption) on the Continent as data received from brokers suggest.

Table 17

Traded volumes in futures/forward contracts as a percentage of national electricity consumption (June 2004 - May 2005)			
	power exchanges	OTC brokered	power exchange + OTC
OMEL - Spain	no exchange trading	negligible	n.a.
GME - Italy	no exchange trading	n.a.	n.a.
Nord Pool - Nordic region (2004)	151%	n.a.	n.a.
EEX -Germany	74%	565%	639%
Endex - The Netherlands (since dec. 2004)	39%	509%	548%
Belgium	no exchange trading	22%	22%
Powernext - France	6%	79%	85%
EXAA - Austria	no exchange trading	n.a.	n.a.
Pol PX - Poland	no exchange trading	n.a.	n.a.
UKPX - UK	0%	146%	146%

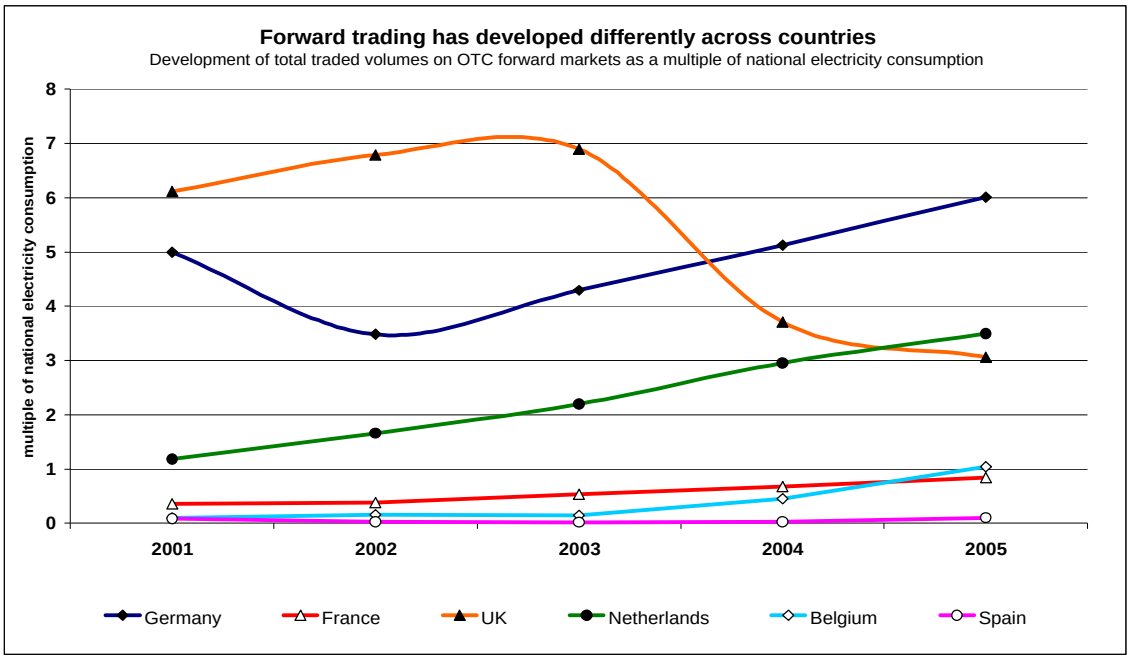
Source: exchanges' and brokers' data
Note: OTC brokered numbers refer to volumes reported to us by major energy brokers.

(357) Figure 42 depicts the development of total traded volumes as a proportion of national electricity consumption. The figures are derived from assessments of respondents in the sector inquiry that actively trade on European wholesale markets. In terms of trades a number of continental markets saw their volumes rise. Especially, the German and the Dutch markets experienced increasing OTC volumes.

190 In Spain only electricity traded via OMEL is entitled to receive capacity payments. In Italy the Single Buyer (Acqirente Unico) apparently covers an important share of its energy requirements to supply the captive market segment on GME. This contributed largely to a rise in spot traded volumes from 29 % in 2004 to 64% in 2005 (January – May). On the Nordic market there is a need for market participants to transact via Nord Pool once crossing different price areas, since the market mechanism applied there is also implicitly used to allocate limited transmission capacities between different price regions.

191 Only some minor transactions are executed one-year ahead of generation or more. This concerns output from cogeneration and renewable unit. Some generators reported however that also this electricity is increasingly sold day ahead.

Figure 42



Source: Energy Sector Inquiry 2005/2006.

(358) The UK is the only market in the comparison where traded volumes have significantly declined during the last two years. This is often ascribed by respondents to ongoing vertical reintegration of the industry, i.e. the trend to bring independent generation and supply businesses into a single operation under the same ownership. Volumes continue to be quite low in France and in Belgium owing to the high level of concentration and vertical integration in these countries.

I.3.6. Number of market participants

(359) Wholesale markets do not only need electricity but also a large number of market participants trading actively. The numbers in Table 18 are based on the data we have received from major brokers.

Table 18

Number of active market participants on forward and futures markets			
	total number of participants trading	local generators	pure financial traders
Nord Pool	36	16	8
Germany	34	8	10
UK	23	12	7
France	20	2	4
The Netherlands	18	5	5
Belgium	5	1	0

Source: exchanges' and brokers' data

Note: The number of participants in the table represents companies that are reported to have traded yearly or seasonally benchmark contracts over the period January-May 2005 and represented at least 0.5 % of the total volumes traded in those contracts.

(360) The total number of participants in the comparison given in the table includes not only local utilities and financial players but also trading affiliates of incumbents established in

other European countries and major oil and gas companies. All market participants act on the market as both sellers and buyers. The number of active participants on the power exchanges (EEX, Powernext) trading futures products is significantly lower than on the respective OTC markets.

(361) Nord Pool together with the German OTC forward market has the highest number of participants and also attracts the largest number of financial traders, followed by the UK, France Netherlands and Belgium. The number of pure financial traders is a useful indicator, since traders only enter markets once they are comfortable with the level of activity and consider that they can get in and out of trading positions relatively easily.

(362) It is interesting to note that although the total number of trading participants is very similar in the UK and France, the UK forward market has six times as many local generators and suppliers as the French. In France there are also relatively few pure financial traders. These relations suggest that in France trading is mostly pursued by affiliates of incumbents in other European countries and – to some extent – by oil and gas companies active in the electricity business.

Table 19

Number of active market participants trading electricty day-ahead on selected power exchanges

	Number of sellers	Number of buyers
Germany - EEX	35-26	31-36
France - Powernext	27-28	29-32
The Netherlands - APX	23-24	24-22
Austria - EXAA	21	22
Sweden - Nord Pool	24	7
Denmark West - Nord Pool	19	16
Finland - Nord Pool	14	9
Denmark East - Nord Pool	7	7
UK - UKPX	18-19	15-19
Spain - OMEL	15-13	6-7
Italy - GME North	15-14	26-21
Italy - GME Sicily	7-8	9

Source: power exchanges' data

Note: The number of participants in the table represents companies that are reported to have traded spot electricity over the period January-May 2005 and represented at least 0.5 % of the total volumes traded. The values are given in ranges, since the number of participants change depending on the hourly product in question. The first values in the range represent the number of participants traded 'Hour 3', the second ones the number of participants traded 'Hour 12'. For data availability reasons no such distinction is made for EXAA and Nord Pool

(363) The number of market participants trading spot electricity on power exchanges is presented in Table 19. The number of participants trading in spot markets compares well with those trading forward contracts on OTC markets. On most power exchanges the vast majority of participants act in general as both sellers and buyers of electricity. It is important to note that on most power exchanges a relatively small number of market participants accounts for a large part of the overall spot volume traded on both the selling and buying side. This is especially true for OMEL of Spain, GME of Italy and Denmark West on Nord Pool. Reference is also made to the chapter II.1.

II. Issues

(364) Whilst the electricity markets underwent significant changes over recent years (e.g. creation of power exchanges in many Member States) and some significant progress has been made in the creation of a single market place, it is currently the overall perception of many market participants that significant efforts are still needed to create a competitive common market for electricity.

(365) It is not the purpose of this report to downplay the progress made in the liberalisation exercise, but to analyse where many market participants currently see major deficiencies that still need to be overcome. The focus is thus on problem identification. As for gas the issues identified by market participants can be grouped into five large areas:

1. concentration and market power,
2. vertical foreclosure,
3. lack of market integration,
4. lack of transparency, and
5. prices.

II.1. Concentration and market power

II.1.1. Introduction

(366) One of the main concerns expressed by market participants in the sector inquiry is the concentration in national wholesale markets (whether in terms of ownership of generation assets or in terms of trade in a given product or exchange forum) which gives scope for exercising market power. In general the larger generators in a given national market found that the market was competitive whereas smaller generators, retailers without generation, traders and industrial customers found that there was scope for market power and disputed that the prices were at competitive levels.

(367) The following customers' views on the functioning of the spot and forward markets illustrate this:

Customers' views on the functioning of spot and forward markets

"There is an oligopoly on the supply side (…) accounting for 80% of generation output."

"French and Belgian markets are dominated by single players – thus distortions can easily occur there."

"Forward and futures prices at EEX do not react to supply and demand. A very dry summer such as 2003 drives up prices, the end of the dry period should thus result in a price decrease. However a downward trend after a price peak is not observable. Obviously the few players at the power exchange are able to prevent price decreases by limiting the offer."

(368) The sector inquiry was launched to carry out a competitive assessment of electricity markets notably in order to investigate the above allegations and to assess the reasons for rigidity in prices. This chapter starts the competition assessment of electricity markets by

looking, in line with traditional competition assessment, at levels of concentration using conventional indicators such as market shares. However, due to the characteristics of the electricity markets such indicators are insufficient to assess the scope for market power. Hence, this chapter will present preliminary results from a set of additional indicators that could reveal to what extent players are able (unilaterally or collectively) to influence prices. This set of indicators does not exclude the use of other possible indicators at a later stage.

(369) The organisation of this chapter is as follows. After explaining in section 2 how the Commission traditionally defines electricity markets, section 3 will present concentration in generation using conventional indicators. Results of similar indicators in the level of concentration in trade on forward markets and power exchanges are presented in section 4. Subsequently, in section 5, preliminarily results are presented using additional indicators for power exchanges and generation aimed to assess in more detail the extent to which electricity markets are vulnerable to manipulation based on market power. A conclusion ends this chapter.

II.1.2. The relevant markets

II.1.2.1. Product market

(370) The relevant product market in this analysis is the wholesale trade in electricity. Previous analysis of the Commission[192] has defined the wholesale supply of electricity to cover the production of electricity at power stations and the import of electricity through interconnectors for purpose of resale to retailers or to a lesser extent directly to large industrial end-users.

(371) Some market participants have indicated that product markets could be narrowed down according to the time of delivery. For instance, one could distinguish between peak and off-peak periods because of the different nature and level of demand in those periods. Others suggested even narrower markets down to hourly markets. For the purpose of this report it is not necessary to take any position on further refinements of the relevant product market.

(372) When analysing whether operators have market power giving them scope to influence prices, the Commission looked in particular at two specific products (one year forward products and day ahead products) sold on power exchanges and brokers' platforms since they provide the main public price indicators in electricity markets. In this respect it is important to underline that these contracts are analysed below as different segments of the same product market i.e. do not constitute a relevant market under EC competition law.

[192] See i.a. cases COMP/M.3440 EDP/ENI/GDP, COMP/M.3696 E.ON/MOL, COMP/M.3729 EdF/AEM/Edison, COMP/M.3867-Vattenfall/Elsam and Energi E2.

II.1.2.2. Geographic market

(373) As regards the geographic market, despite efforts by the Community to reduce barriers between the different markets in the EU, the Commission has usually found that the geographic markets are most of the time national in scope[193], but that they may sometimes be smaller[194] or larger[195].

(374) Relevant elements which support the existence of a smaller or larger market include system design, the existence of congestion at points in the grid, the existence of price correlations and price differentials and the differing nature of supply and demand on both sides of congestion points (in particular the existence of an operator that is indispensable to meet demand[196]).

(375) Annex A that is attached to this report includes a preliminary analysis of the regional scope of certain wholesale market. A complete analysis would have to include further supply and demand substitution of assessment, in particular the systematic assessment of whether there are operators who are indispensable to meet demand (calculation of residual demand). Given the need to do such an assessment on a very detailed basis, it was not considered useful to do such an assessment for all markets, but to leave that to further investigation in individual cases. However, on the basis of the analysis carried out so far, all markets will be considered to be national in scope, except Denmark and Italy, where regional markets clearly exist.

II.1.3. Concentration in generation

(376) Many market participants complain about price distortions linked to the degree of concentration in generation. It is often argued that generators' ability to influence the electricity price levels are due to the characteristics of electricity - the non-storability of electricity, the high inelasticity of demand, a very wide spectrum of costs of production and a price equal to the highest offer made in power exchanges. According to market participants generators can influence prices either

- by withdrawing capacity (which may force recourse to more expensive sources of supply) or
- by imposing high prices when they know they are indispensable to meet demand.

(377) In the first scenario, the withdrawal of capacity is profitable if the "loss" on electricity not being produced is exceeded by the increase in profit for the remaining electricity sold. Large capacity portfolios (in particular large low marginal cost generation capacity portfolios) can have such an effect because the higher price that results from the withdrawal of capacity will be more than compensated by substantial additional profits

193 See i.a. cases COMP/M.3440 EDP/ENI/GDP, COMP/M.3696 E.ON/MOL.

194 See case COMP/M.3729 EdF/AEM/Edison

195 See cases COMP/M.3268 Sydkraft Graninge and COMP/M.2847 Verbund/Energie Allianz.

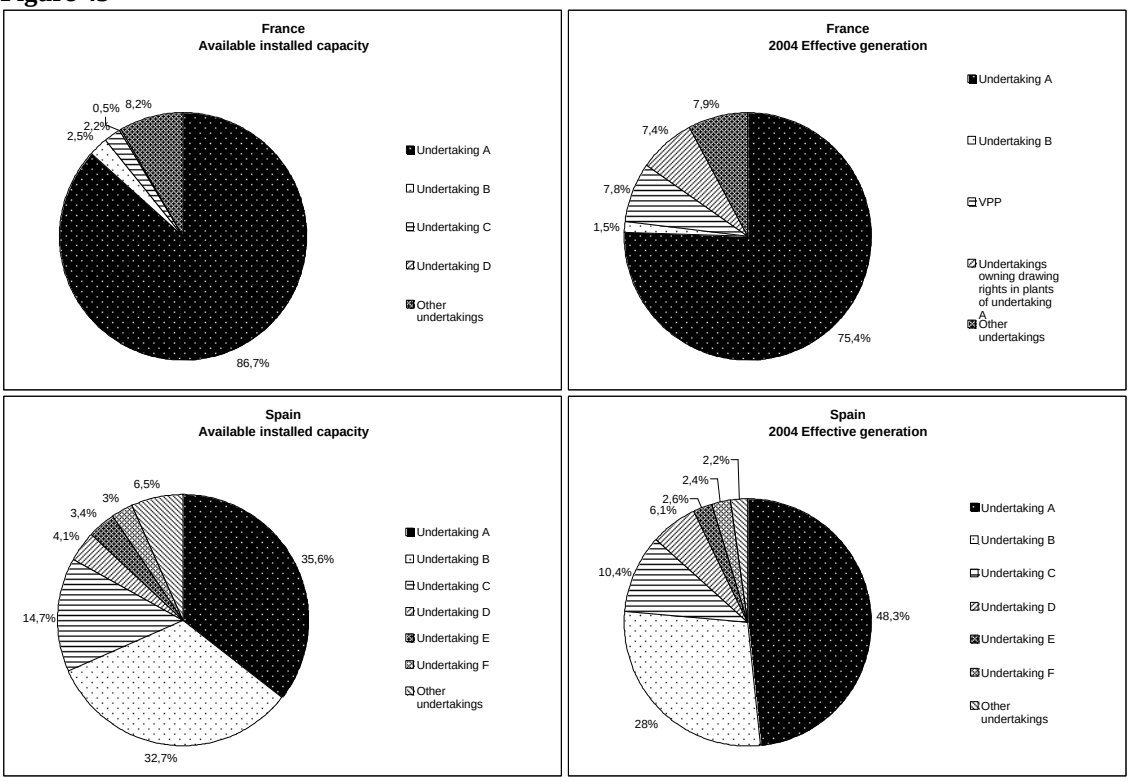
196 An operator is theoretically indispensable to meet demand if total demand (D) in the area is larger than the sum of the capacity (SC) of the other generators in the area and of the import capacity (IC) of the area. Given the little flexibility of demand and provided that the capacity of this operator is much larger than (D-SC-IC), such an operator would be able to raise prices without constraint.

from the generation assets being used. Assessing overall concentration of generation assets thus helps to identify the scope for such profitable withdrawals of capacity.

(378) In the second scenario, it is possible to raise prices ("excessive pricing") even with a relatively small portfolio because the structure of the generation assets and indispensability of certain assets to meet demand at parts of the merit curve. The higher the concentration in the relevant parts of the merit curve concerned the greater is the scope for influencing prices (as presented in chapter I.1). This will be elaborated later in this chapter.

(379) Although the extent to which generators may successfully influence the price level, may not (always) correlate with the level of concentration, it is a necessary element of the analysis of electricity markets across Member States. Figure 43 shows the share of available capacity and of effective generation of the main operators in France[197] and Spain. Charts for other Member States can be found in annex B.

Figure 43



Source: Energy Sector Inquiry 2005/2006

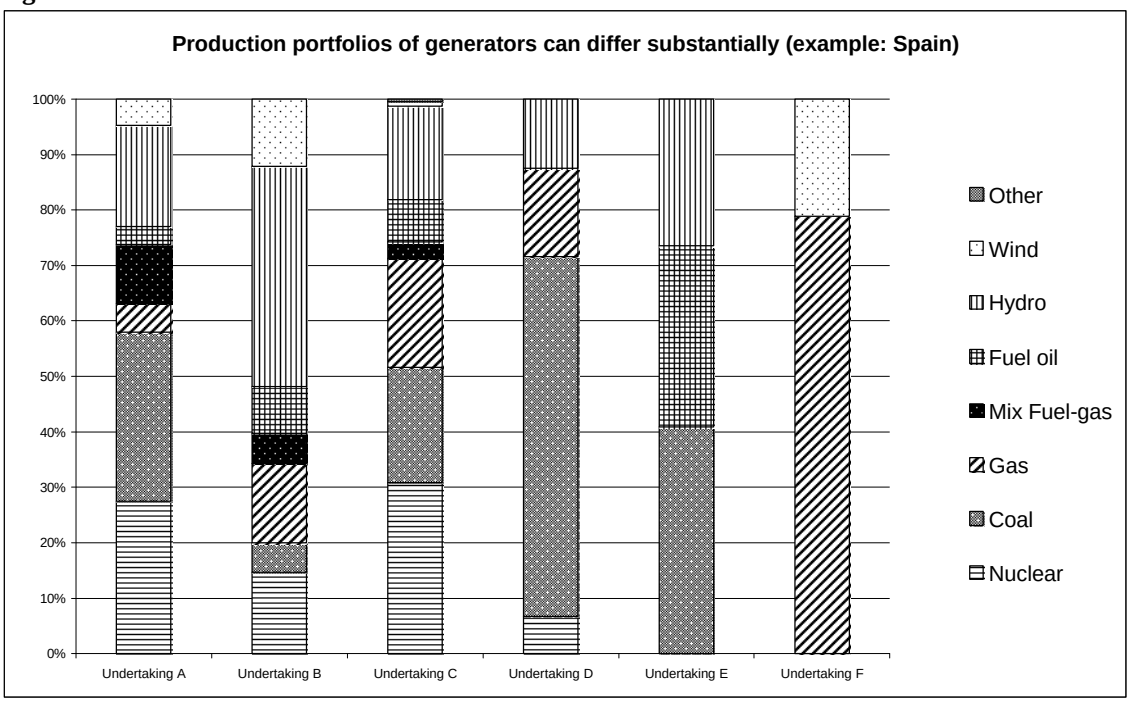
(380) The charts show that the production assets remain largely in the hands of one or a few large operators. This stems from the pre-liberalisation concentration of generation, which was rarely mitigated by decisions to force divestitures of the incumbent operators. Further, the strong position of incumbent operators has not been eroded in a significant way by investments in generation by new entrants. Indeed, there has been little new build of generation facilities across Europe, though in the past few years new generation has involved a build-out of new gas-fired plant in Italy, Spain and the UK and some new

197 For France the VPPs are plotted separately since this share is not controlled by the major generator. That being said, it is unclear to what extent VPPs limit the scope of market manipulation.

wind and other renewable generation facilities, primarily (in terms of total size) in Spain, Italy, Germany, and Denmark.

(381) The charts also point to the possibility that companies with a limited share in generation capacity might have market power at certain moments. For instance, in Spain, the second largest operator has almost the same size of installed capacity as the largest one (and both of them represent one third of total capacity respectively). However, the second largest one accounts only for a quarter of the effective output of the largest operator (while the two of them represent three quarters of the total production). This is because the main operator predominantly operates base load plants (essentially nuclear and coal), as can be seen in Figure 44, whilst the second largest operator is likely to serve more peak load demand (especially with hydro plants). Whilst further analysis would certainly be necessary the largest producer might have scope for profitable withdrawals of capacity according to the first scenario mentioned above, whereas the second largest operator might rather have scope for charging high prices at times of peak load.

Figure 44



Source: Energy Sector Inquiry 2005/2006

(382) The different possibilities to influence prices by the two generators concerned can be further explained by recalling the analytical concept of the merit order explained in chapter I. Figure 44 shows the technologies used in the portfolios of the different generators. As regards the largest operator, most of its plants will be on the left of the merit curve, representing generation with low marginal costs. If it withdraws capacity (i.e. limits its production), the curve will shift to the left and force recourse to more expensive plants to meet demand. Given its very large portfolio, this operator may compensate fully the lack of production with the increase in prices.

(383) The example of the second-largest operator shows on the other hand the scope for market power resulting from control over fewer plants which are more on the right of the curve or which are based on hydro. If an operator owns most of the plants on the right of the

curve, then it can increase prices with little risk of being replaced by another operator. It is precisely for this reason that the distribution of the power generation technologies becomes relevant. It is however important to underline that having scope for influencing prices does not automatically mean that market power was abused in an anticompetitive manner, as many market participants claim. Rather, this first step in the analysis serves to identify possible scope for influencing prices.

II.1.4. Concentration in trade

II.1.4.1. Introduction

(384) Analysing concentration in traded forward and spot markets is important because many retailers wish to procure their demand through these markets, be it partly or entirely. Similarly many generators wish to secure their sales through these forward markets. In addition forward (and sometimes spot prices) established on observable markets (broker's platform and power exchanges) provide an index for bilateral wholesale contracts and for retail sales to large users. So these markets serve as an important means of sale and purchase and develop reference prices.

(385) Below we analyse first forward trading and then spot trading.

II.1.4.2. Forward markets

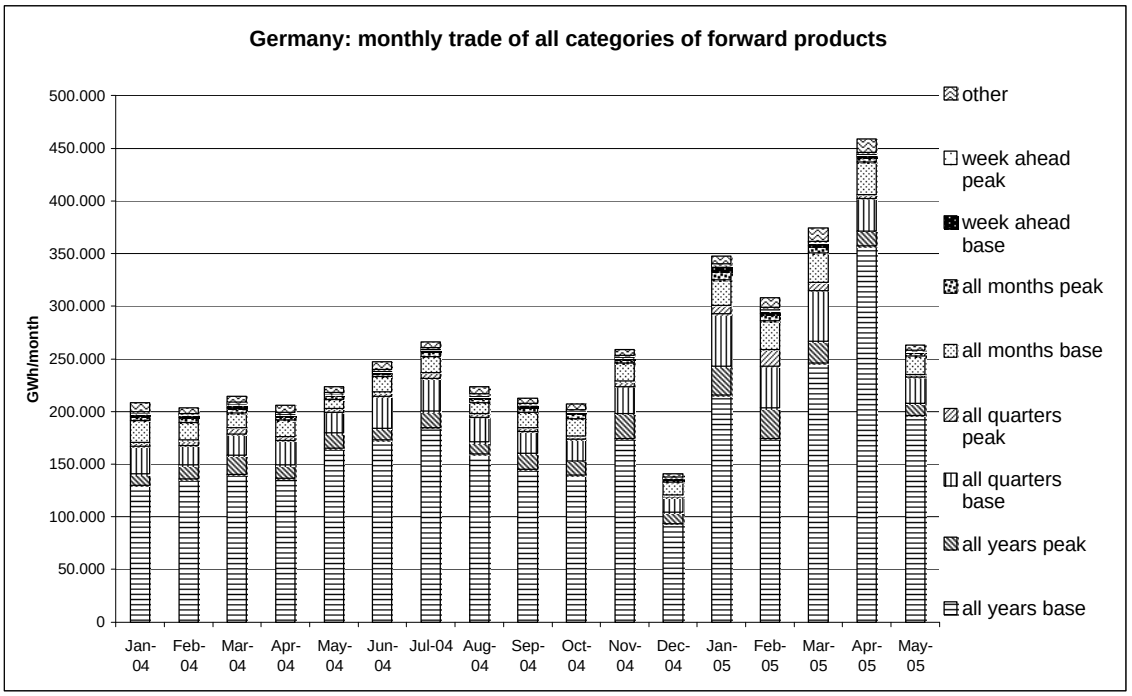
II.1.4.2.1. Degree of concentration in forward markets

(386) The most traded product by far on forward markets is the yearly contract for base load hours. An exception is the UK market where products for different seasons are the most traded[198]. Figure 45 shows for example the proportion of trade of the different forward products in Germany. Further, the yearly forward prices are the main forward price indicator in all markets, for both wholesale and downstream retail contracts.

(387) Thus, it seems that yearly base load products are a good candidate to investigate concentration in trade in forward markets. For this purpose the sector inquiry has collected and aggregated the sales and purchases per operator on all OTC trading platforms and on the power exchanges which trade forward products. Buying and selling have been separately assessed.

[198] This was also the case in Nord Pool until 2004 when yearly forward products started to be traded much more.

Figure 45



Source: Energy Sector Inquiry 2005/2006

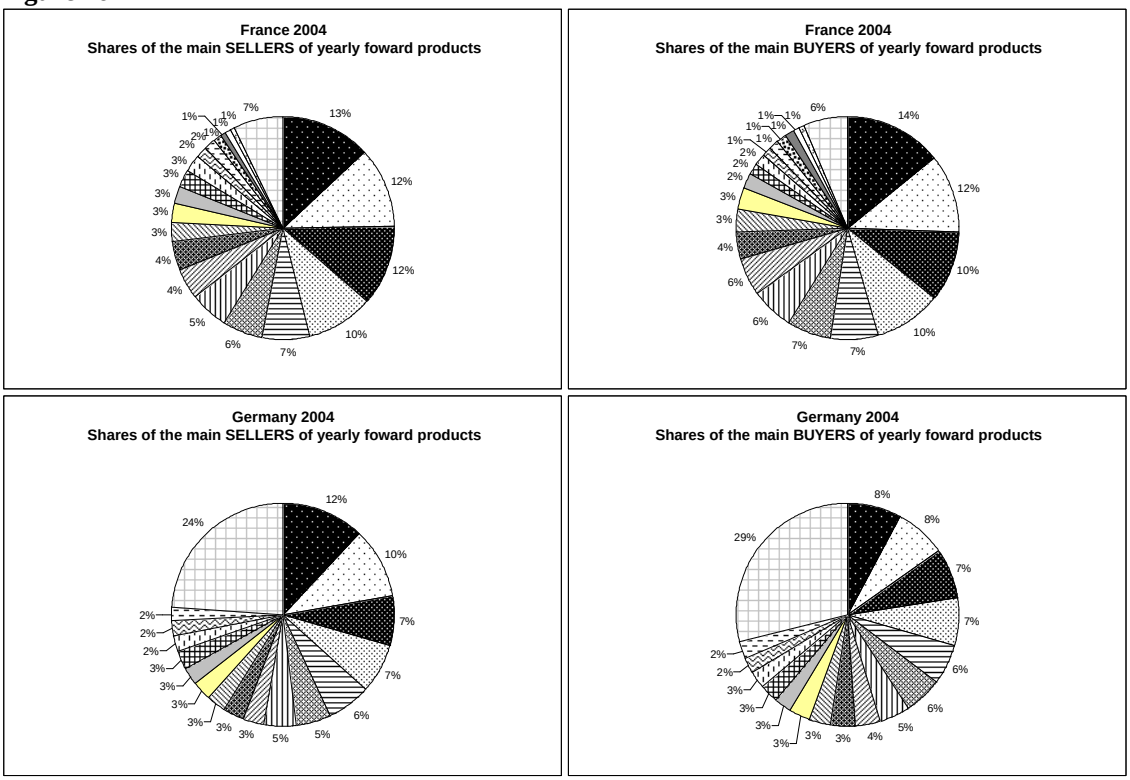
(388) Figure 46 illustrates for France and Germany in 2004 the trade in yearly forward contracts (indicating the shares of the main sellers and the main buyers separately[199]). Charts for other forward markets can be found in Annex C. The charts represented here and in the annex show that, except for Belgium, the degree of concentration is not comparable to that in generation. Given the many transactions that take place, the trading affiliates of main generators in any given market usually represent together between 30% and 40% of all sales. Furthermore, trading affiliates of the main generators represent together between 20% and 30% of all purchases. The other large market participants are usually the trading arms of the large European generators located in other markets as well as some "pure traders" (i.e. operators without generation assets). The top five players on the selling side are usually the top five players on the buying side, though not in the same order.

(389) That being said, it is important to note that in all markets (except Belgium) there are at least two participants without generation assets and without retail activity in that market, which can be found among the top five players. Further, at least one of these two players is a "pure trader"[200]. This may suggest that some "pure traders" have reached a sufficient degree of knowledge and confidence in the markets to provide liquidity and arbitrage in the markets.

199 Note in that respect that the same colour does not correspond to the same undertaking in both pie charts (for sellers and buyers).

200 In one market, this pure trader is even the biggest trader overall (in terms of total and purchases).

Figure 46



Source: Energy Sector Inquiry 2005/2006
Note: The pattern represents in each Figure the category "other undertakings", i.e. the aggregation of all undertakings which have not been represented individually in the Figures.

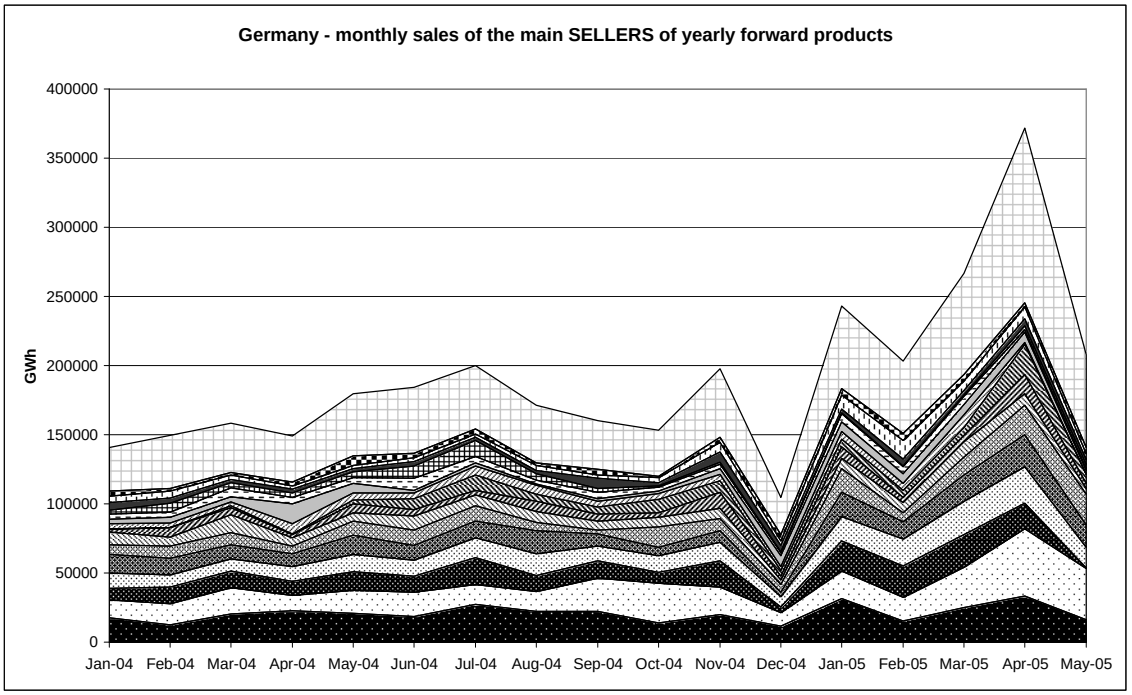
(390) An important result, shown in the charts, is that shares in trade do not reflect shares in generation. Furthermore, for the markets analysed, almost no trading platform has been identified where operators systematically have a dominant position on supply or demand as is claimed by a number of market participants[201].

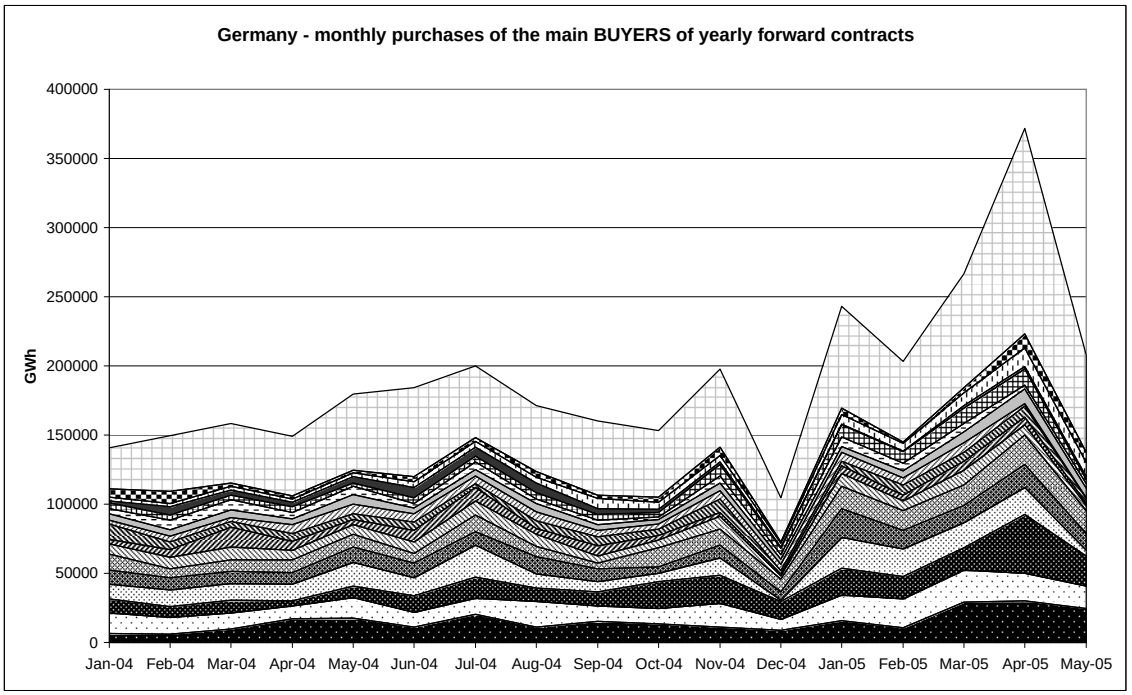
II.1.4.2.2. Evolution of concentration in forward trade over time

(391) Whilst the overall concentration levels may look reassuring in the yearly forward market contract, at certain moments in time there may be a high level of concentration which is not shown in the static presentation in the previous chart. Figure 47 therefore shows the monthly evolution of sales and purchases in Germany during the period January 2004 – May 2005 (see Annex D for all other forward markets). Though more detail may be required for a more thorough analysis, such as hourly evolution, it gives a preliminary insight into concentration at different times.

201 In that respect, it is important to note that in most markets, there are more than ten very active participants which trade on all platforms and can thus arbitrage between them. Thus even if there had been a main operator on a given platform, it would have been arbitraged against other platforms. That being said, if there had been a main trader behind a given platform it might have been able to give signals through its bids and offers on that platform: that is the reason why it was useful to check this allegation.

Figure 47





Source: Energy Sector Inquiry 2005/2006
Note: The pattern ▭ represents in each Figure the category "other undertakings", i.e. the aggregation of all undertakings which have not been represented individually in the Figures.

(392) The monthly evolution of relative trading positions for the annual contract during the period January 2004 – May 2005 shows that, except in Belgium[202] and in the Netherlands at certain moments in time, there does not seem to be concentration at a monthly time scale. In Germany the relative proportions of trade on both sides of the market per player

202 The charts for Belgium cannot be shown given the very few operators actively involved: it would reveal the strategy of those operators.

remain rather constant, though in December 2004 and April 2005 the evolution of the market shifts significantly. As regards December 2004, this decrease is due to the fact that at the end of the year the trading of the product of the following year stops. As regards April 2005, this peak may be related to the change that occurred in CO2 trading. The Nord Pool market is growing fast because of the replacement of the seasonal products by yearly products, though this has hardly altered the relative proportions of trade per player. The UK market on the other hand is drying up and trade of all operators seems to be reducing similarly. In France, there are important variations but trading shares of most operators change accordingly. In the Netherlands on the other hand, at times of decreasing trade, the main sellers become fairly important and the two main sellers can reach up to 50% of total sales, which is a fairly high level and creates room for those operators to move the market. In Belgium, the concentration can become even more acute in certain months than the figures in the preceding section suggest.

(393) It is also clear from the data gathered that in the beginning of the year 2005 a number of new pure traders entered the market. An increase of trading activity by some of the main players was also observed in that period.

(394) In addition, the evolution of the net position (sales minus purchases) of the main operators active on each forward market was studied, as it shows their underlying sales and buying strategies (e.g. financial traders avoiding large open positions). For obvious confidentiality reasons, the corresponding graphs cannot be reproduced here[203]. However it can be said that in certain markets the main generators have so far been able to take much larger net positions in the forward market than all other participants. It remains to be seen if the generators in those markets could affect the markets by changing abruptly their net positions. It also remains to be analysed why certain generators were not taking any net positions during certain periods of time. For further analysis on this issue reference is also made to chapter II.2.

II.1.4.3. Concentration in spot markets

(395) Power exchanges, where one can trade day-ahead on an hourly basis, often function as a last resort to close open contractual position before gate closure. Alternatively one may be exposed to balancing market prices that in some Member States are highly unpredictable and are reported as (economically) punitive by certain market participants[204]. Hence, in contrast to forward markets, there are fewer possibilities to substitute away from the product concerned, e.g. by delaying the purchase. Therefore high levels of concentration on power exchanges may indicate substantial scope for

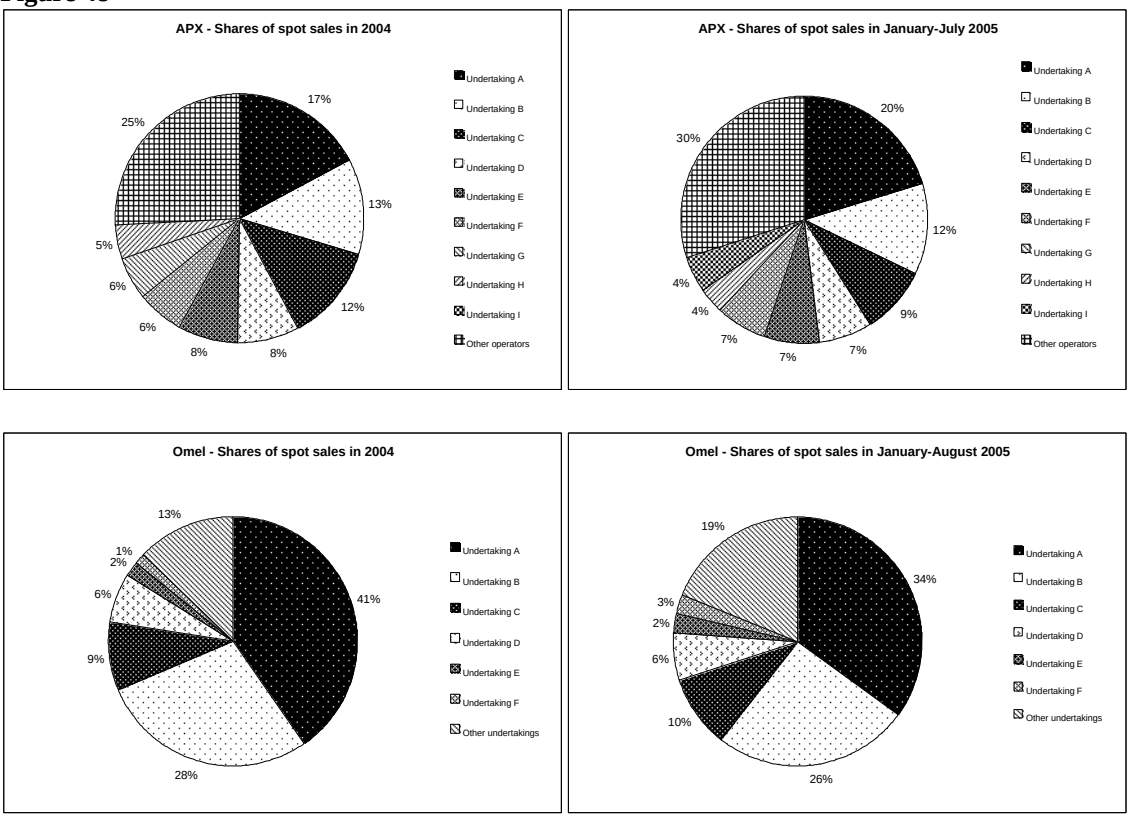
[203] We have in particular studied the evolution of the cumulative net position up to the moment of delivery, for instance the cumulative net positions (sales-purchases) of each operator in yearly forward products all through the year 2004 until all Calendar 2005 products have either been physically delivered or turned into shorter-term contracts. The graphs presenting the evolution of the cumulative net positions show three categories of operators in all markets during 2004: first there were a number of operators (usually retailers with or without generation) who gradually increased their net buying position during the year, second there were a few operators (usually generators) who increased gradually their net selling position during the year, and thirdly there were a number of operators whose net position varied in both directions but who remained (except for a few of these "traders") in absolute terms usually far below the cumulative net value of the operators in the two other categories. This seems to indicate that there was a rather cautious approach on both the buying and selling side during 2004, which avoided the rush that would happen if for instance all buyers had increased their net purchases at the same time. That being said, some of the net positions in trading did not correspond to the net positions studied in the chapter II.2 on vertical foreclosure. Further, in a number of markets, the categories and the behaviours were much less straightforward in the first half of 2005.

[204] Further work on balancing regimes will be considered in the next part of the sector inquiry.

exercising market power. Some market participants have also claimed in their answers that generators may "dictate prices" on power exchanges. Thus, this section measures the level of concentration on power exchanges.

(396) As explained above, it is important to keep in mind that not all power exchanges with spot markets have the same underlying design. Some thrive on regulatory constraints (OMEL, GME, Nord Pool), others are of a more voluntary nature (APX, EEX, Powernext). Thus the volumes traded on the respective market places might vary considerably. Figure 48 shows the degree of concentration of the various power exchanges in 2004 and during the first five months of 2005 (further graphs in Annex E).

Figure 48



Source: Energy Sector Inquiry 2005/2006

(397) In the first category of power exchanges (Spain, Italy and Nord Pool) the concentration in generation finds – with one exception (Italy's North zone) - direct expression in a rather stable equivalent concentration in the power exchanges[205]. This situation does not reduce the concerns that there is scope for market power.

(398) In the second category of power exchanges (France, Germany and Netherlands) the power exchanges display a lower level of concentration and also less correlation with concentration in generation. Also the stability of the shares is low in these power

205 For this analysis, it is necessary to take into account the electricity sold by TSOs on certain exchanges (TSOs appear as a separate undertaking in the corresponding graphs). Electricity is sold by TSOs on exchanges in particular in Italy and Denmark. Regulation in Italy mandates the TSO to sell on the power exchange the large amounts of electricity sold under regulated pre-liberalisation contracts (so-called "CIP 6" contracts). In Denmark, the TSOs sell wind power on the exchange: the corresponding amount of electricity has varied substantially between 2004 and 2005.

exchanges for the different operators[206]. However further assessment in the light of the comments on additional indicators is necessary.

II.1.5. Additional indicators

(399) In this section a more detailed analysis is presented of the scope for market power on power exchanges (possible excessive pricing) and generation (possible withdrawals of capacity).

(400) In this respect it should be kept in mind that there are a number of objective factors that may influence electricity prices (cost of fuels, pricing-in of CO2, constraints on interconnections, etc), as explained in other chapters. These factors and constraints make it more difficult to identify the effect of an anti-competitive practice as some of these constraints (e.g. CO2 emissions) are reported to have a very large impact on prices. The assessment that follows does not at this stage aim to quantify the impact of such practices, but tries to identify whether they were possible.

II.1.5.1. Possible scope for excessive pricing

(401) As indicated above, a relatively low market share on a power exchange does not necessarily mean that an operator cannot influence the price level. Indeed, it all depends on the price level of offers of the other operators. For instance, if one operator owned most of the more expensive plants required to meet demand at times of higher demand (concentration in the right of the merit curve), this operator would make most of the offers determining the clearing price at times of peak demand and would face few competitive constraints[207]. In other words, the residual demand is supplied by a few or just one operator. The focus of the assessment below aims to identify for all exchanges whether some operators are in such a position. Accordingly, it is the aim at this stage to identify if the operators had the scope for excessive pricing but not to check if they actually used it.

II.1.5.1.1. Price setting frequency

(402) As a first rough measurement of concentration in the right of the merit curve, we have identified in all exchanges for each operator the number of hours when this operator "set the clearing price", meaning the hours when its selling bid was equal to the clearing price[208]. This gives an indication of how often an operator makes selling bids at the

206 It shows in particular in the difference of aggregated shares between 2004 and 2005. It has also been checked that variations month by month and the variations of shares of sales of generators month by month are larger in this second category of power exchanges.

207 In that respect it is important to note that the merit curve will not be perfectly reflected in the power exchanges: especially in smaller exchanges, it is only a very small part of the merit curve that is reflected by the offer curve in the power exchange. However, since generators usually try to optimise their most expensive plants on the basis of spot prices, the right of the merit curve will be much better reflected in the offer curve on the power exchange than the left of the merit curve.

208 Depending on the clearing system used by the power exchange, the price for a given hour may be established by interpolation between selling bids. In such cases, the "operator setting the price" was defined as the operator(s) whose selling bid had a price closest to the clearing price. It may also be possible that several operators had the same selling price equal to the clearing price or were as close to the clearing price: this leads to totals exceeding 100% in a few cases. Finally, during some hours all sellers who had been selected had made offers at zero (the price was then not equal to zero because of interpolation with the first bid at a non-zero price): in those cases no operator was identified.

clearing price. Hypothetically, if only one operator "sets the price" most of the time, it means that there are very few, if any, alternative offers around the clearing price most of the time. The operator builds-up knowledge about the inelasticity of demand on a specific part of the supply curve where he operates by comparing his bids with the exchange clearing price. If demand is relatively inelastic, he can increase his selling price without the risk (or with little risk) of being replaced by another operator.

(403) The frequency of price-setting on the main EU exchanges has been checked month by month for 2004 and for the first eight months of 2005. Table 20 shows the frequency of price setting of the three main "price-setters" in each of the exchanges (or area of the exchange when the relevant market is smaller) in the first eight months of 2005; the number of operators with an average frequency above 5%; as well as the maximum percentage of the number 1 operator in any given month during 2005. For zones in Nord Pool and GME, the frequency is calculated only on hours during which the zone is isolated from other zones[209]. This naturally produces higher figures than for other exchanges. In order to provide a complete picture for Nord Pool, the calculation has also been made for the most common aggregation of zones (all zones together), which leads to lower percentages.

(404) This indicates that in EEX, APX and Powernext, there are a fairly large number of operators making offers of electricity resulting in setting the clearing price. The figures for 2004 in those exchanges further show that the shares of the main operators vary over time and that even the positions of the main operators have varied. The figures presented in the above table are usually similar but sometimes higher when only including peak hours[210]. The fact that there are many operators involved in price setting despite concentration in generation is possible because there are smaller generators which apparently have "marginal plants" and because a number of market participants have bought electricity from the main generators in VPP auctions or own drawing rights in plants of the main generator(s)[211]. Also, some of the price-setters are traders which arbitrage between market segments such as spot exchanges and OTC trade. This measurement does not indicate thus that there was a single operator very much influencing the spot price in those markets, although the situation may need some further monitoring, particularly for Powernext. In addition, it would be important to verify also the buying side as generators may also influence the price through purchases[212].

209 The zones selected are the ones in the EU which are most often isolated (Sweden is almost never isloated) as well as South Norway (another often-isolated zone) for comparison purposes.

210 Peak hours have been defined for that purpose as the hours covering the period 8:00-20:00 on working days.

211 These operators are different from traders who do not have any retail business in a given market. Such traders, have to sell the electricity that they still have remaining the day before delivery (e.g. if they have bought that electricity in the forward market), either in the spot trading of the market where they bought it or in the spot trading of a neighbouring market if they can export the electricity or sell it OTC. Accordingly, such traders are present in the statistics of price-setting usually less than in those of shares of sales presented in II.1.3, depending on the possibilities of arbitrage between markets.

212 Indeed, generators often combine buying and selling bids as part of their optimisation process: for instance, an undertaking A with a 50MW plant of a marginal cost of 15 €/MWh, a 50MW plant of a marginal cost of 35.1 €/MWh and needing 150 MW for its retail needs would place a buying bid for 100MW up to the price of 35MW and 50MW above. In other words, that operator would make no selling bids. If the clearing price was (due to interpolation), say, 35.05€/MWh, the measurement above will determine that it is another operator that "set the price", whereas at least both operators influenced the price.

Table 20

Frequency of "price setting" in the main exchanges in 2005					
	N°1	**N°2**	**N°3**	**Number of operators above 5%**	**Maximum percentage in one month**
Omel	32%	25%	10%	5	44%
GME Nord	86%	5%	5%	3	100%
GME Centre South	96%	2%	1%	1	97%
GME Sardinia	80%	19%	1%	2	98%
GME Sicilia	87%	10%	2%	2	98%
Nord Pool WDK	50%	10%	2%	2	89%
Nord Pool EDK	60%	3%	1%	1	100%
Nord Pool SNO	40%	30%	21%	10	63%
Nord Pool FIN	85%	12%	3%	2	100%
Nord Pool all zones together	34%	35%	27%	15	57%
EEX	17%	13%	11%	8	25%
APX	15%	14%	9%	8	18%
Powernext	20%	15%	12%	7	33%

Source: Energy Sector Inquiry 2005/2006
Note: all percentages are rounded, totals can exceed 100%.

(405) On the other hand, in all macro-zones of GME, in West Denmark, East Denmark, and Finland, when they were isolated, there was in 2005 one operator which set the clearing price almost all the time[213], meaning that there was very little alternative offer around the clearing price. With one exception (Sardinia) the figures were roughly the same for 2004. The same statistics were also calculated for the period of peak hours and it provided similar results[214]. This means that there might be room for the main price-setter in each zone to increase its price without having the fear to be replaced by another operator, in other words there seems scope for market power. In the case of Omel, as expected in the section on concentration in generation, the largest price setter happens to be the second

213 The percentages for the main price setter are much higher than the largest share of trade (seen in 2.4.1.3). This is possible because other participants have less expensive plants (as explained in the Spanish case under 2.1.3), or because some other participants even bid at zero (so-called "price takers"). Bids at zero maybe due to the fact that a plant is heat-driven or due to regulatory constraints (the TSO sells into the power exchange wind-power in Denmark and the TSO sells into the power exchange the large amounts of electricity produced under regulated legacy contracts "CIP6" in Italy).

214 The proportion remained the same between operators but, in certain zones the percentage of the main operator in "peak hours"could be one or two points above or below that for "all hours".

largest operator in terms of total capacity, i.e. the one with by far the largest amount of hydro power. Furthermore, the percentage of price setting of this operator reached high proportions (up to 58%) during the summer months of 2005. This would at least give some scope to this operator to exercise market power.

(406) All in all, the price setting frequencies indicate a substantial scope for influencing the prices on certain power exchanges.

II.1.5.1.2. Quantity offered around the clearing price

(407) In addition to analysing who set the clearing price, the sector inquiry analysed in more detail which operators placed bids around the clearing price. For this purpose the interval +/-10 percent around the clearing quantity along the power exchange supply curve was analysed to establish whether any operator offered more than 50% of the quantity in that interval. This goes further than the previous measurement by checking how much the largest operator on the right of the merit curve controls of the bids. This approach is rather conservative given that the +/-10 percent interval represents 20% of the clearing quantity and that some of these exchanges represent a fairly large part of total consumption. For zones in Nord Pool and GME, the frequency is calculated only on hours during which the zone is isolated from other zones. This naturally produces higher figures than for other exchanges. In order to provide a complete picture for Nord Pool, the calculation has also been made for the most common aggregation of zones (all zones together), which leads to lower percentages.

(408) The results shown in Table 21 confirm that the largest price setters in Omel, in the Nord Pool zones included in the table when they are isolated, and in all GME zones except Sardinia are also those placing most bids around the clearing price. At certain levels of demand (particularly in certain months), the main price-setter seems to be in a position to raise prices, provided that it can forecast well enough the separation of zones in the cases of Nord Pool and GME[215].

(409) The same analysis was also carried out on other exchanges. It revealed that in EEX, the concentration around the clearing price has been increasing rapidly in 2005, reaching levels of up to half of the peak hours in a month. This may be a sign that the growth of EEX is now leading to similar characteristics as discussed for OMEL where a larger part of the "peak plants" are being optimised through power exchanges. A similar trend seem to be occurring in Powernext, though at much lower level as the largest price-setter there started in the summer 2005 to offer more than 50% of the quantity around the clearing price for a non-negligible percentage of the time (up to 17% of peak hours).

[215] In general, it can be said that such a forecast is easier when the isolation of the zone occurs frequently (e.g. more than 45% of the time for West Denmark, Sardinia or Sicilia) than when it occurs less frequently (8% of the time for Finland and 11% of the time for East Denmark in 2005).

Table 21

Percentage of peak hours when the largest "price setter" controlled more than 50% of the offers of electricity offered at a price around the clearing price				
	Maximum in a month in 2004	Monthly average in 2004	Maximum in a month in 2005	Monthly average January-August 2005
GME Nord	68%	42%	66%	28%
GME Centre South	100%	100%	100%	100%
GME Sardinia	79%	41%	11%	4%
GME Sicilia	55%	36%	56%	40%
Omel	50%	17%	66%	33%
Nord Pool WDK	100%	80%	100%	87%
Nord Pool EDK	100%	74%	100%	92%
Nord Pool SNO	83%	32%	88%	50%
Nord Pool FIN	73%	27%	95%	31%
Nord Pool all zones together	63%	25%	100%	50%
APX	12%	6%	10%	5%
EEX	25%	11%	52%	25%
Powernext	1%	0%	17%	6%

Source: Energy Sector Inquiry 2005/2006
Note: all percentages are rounded.

II.1.5.2. Impact of generation on prices: a preliminary assessment of the possibilities to withdraw capacity

(410) Generators, due to the characteristics of electricity markets, may also be able to influence prices through withdrawals of physical capacity. This can be done by fully withdrawing a plant or, more discreetly, by making it produce at less than its capacity (partial withdrawals).

(411) The analysis focuses thus on the level of utilisation of power plants of the main generators over a sufficiently long time period. Disregarding special circumstances one would expect plants with relatively low marginal costs to run all hours and plants with relatively (very) high marginal costs only to run at (super) peak hours. If this relation between marginal costs and utilisation does not appear from the data one may suspect that competitive pressure is too low, and that (partial) withdrawal of generation to manipulate the price level during some hours must be further investigated.

(412) In order to identify plants which are not run at their maximum capacity (partial withdrawals), so-called load factors have been calculated (see the definition below) of the main generators for a number of years in Germany and France. In order to identify full withdrawals, one must also take into account the maintenance schedules. At this stage, this has not been done.

(413) The load factor of a plant is the ratio between effective production and the maximum amount of electricity that this plant could have produced in a period, all market terms remaining equal. For this purpose, for each plant and in each period, the number of hours were calculated when it was generating electricity. Multiplying these effectively operational hours with the plant's maximum capacity yields the maximum potential output[216]. The load factor is then equal to the effective measured output during the period divided by its (potential) maximum.

(414) Figure 49 shows the results of the calculations for the main operators in Germany and cover the years 2000, 2004 and the first trimester of 2005. The year 2000 corresponds to the beginning of liberalisation, the year 2004 and the first trimester of 2005 represent the situation after liberalisation and before the full effects of CO2 emission trading were felt. The first line which starts low and increases continuously is the aggregated merit order of all plants of the four main German generators, i.e. the line ranking the marginal costs of all the existing plants. The second line shows the load factor for each plant in the order of their marginal cost (so that points on both curves correspond to one another vertically). The horizontal axis provides the aggregated value of capacity of the plants in the order of their marginal cost.

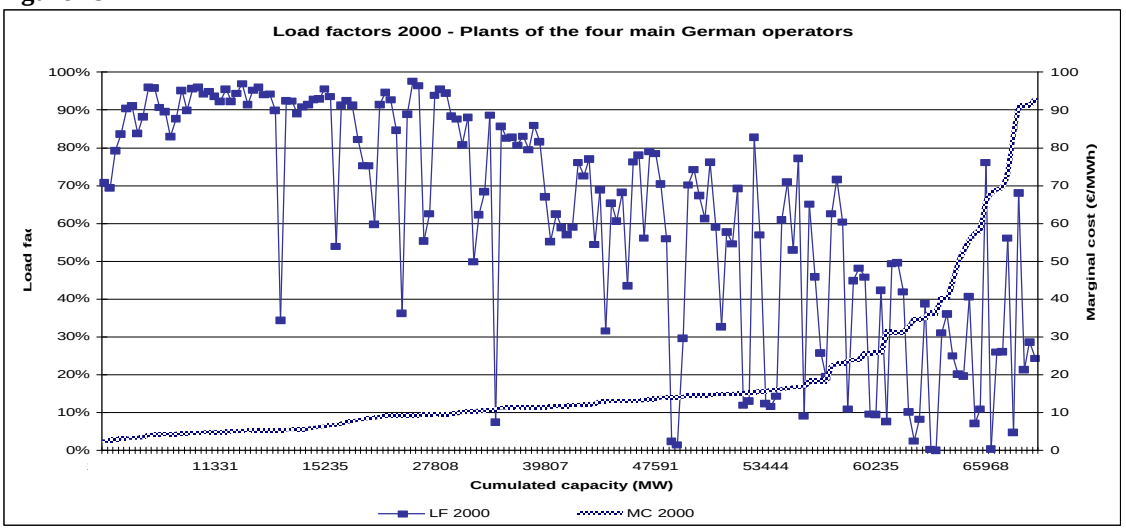
(415) Figure 49 indicates that the correlation between marginal costs and load factors has increased overall throughout the period investigated. Especially, the load factor of the relatively low marginal cost plants is overall on the rise.

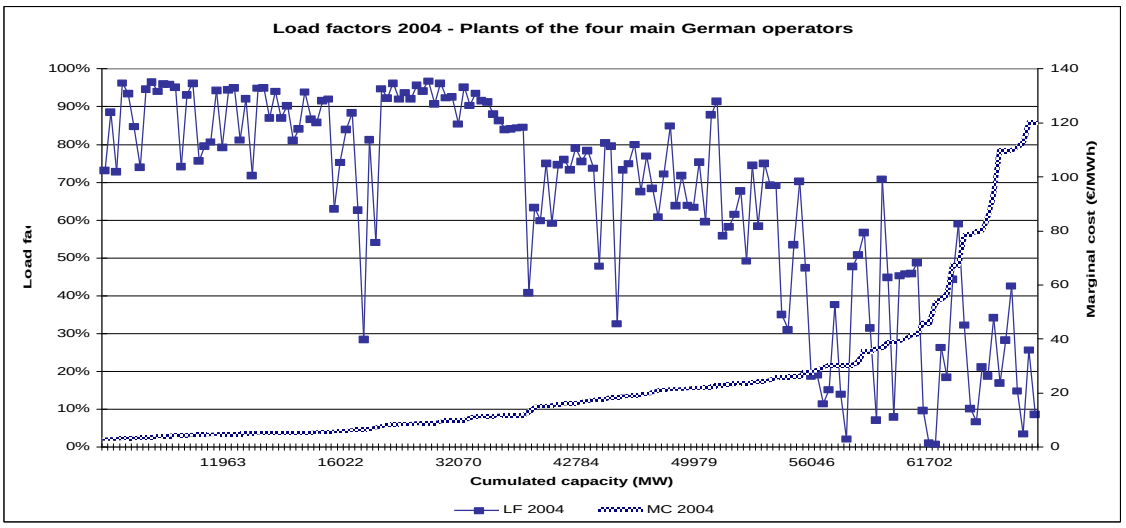
(416) Figure 49 shows that within the groups of plants with marginal costs usually below the spot market level (on average around 28-30€/MWh in 2004 and around 36-38€/MWh in the first trimester of 2005) some were used extensively whilst others were characterised by low load factors. In other words, some plants ran significantly more than other plants with similar or higher marginal cost. There is a variety of possible explanations for this phenomenon: for instance, a plant may be producing heat as well as electricity and needs to run according to the need to produce heat.

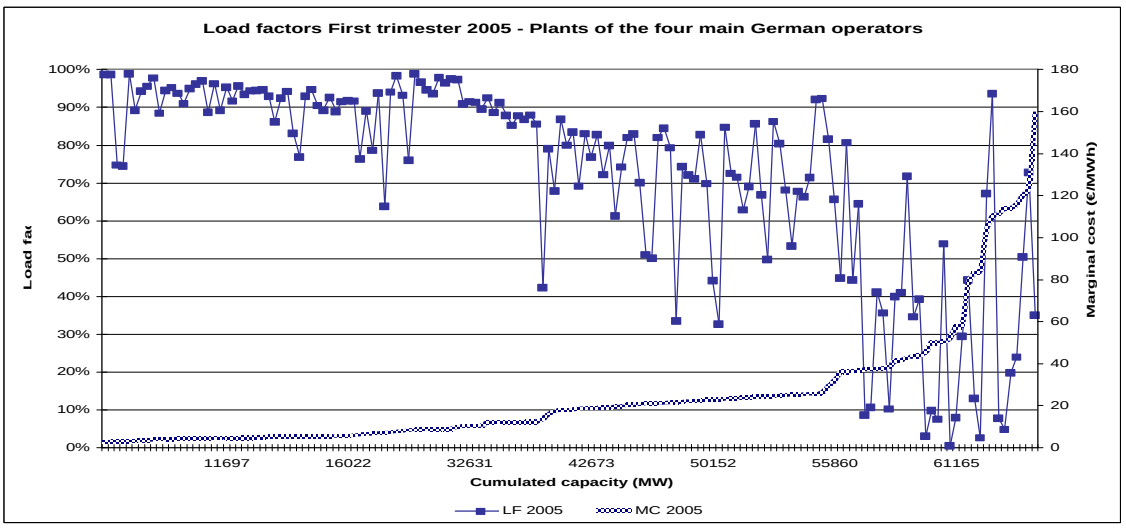
(417) Figure 50 shows the same calculations as those in Figure, but it plots the marginal costs to compare the merit curve across the years (with on the horizontal axes the accumulated capacity for the main German operators). One should keep in mind that, in this chart the plants on the horizontal axis need not necessarily be the same for all years.

[216] This maximum capacity is usually the capacity stated by the generator in its answer to DG COMP questionnaires. However, in a number of cases (especially the cheap plants), the plant is run for a very large number of hours above the nominal capacity. In those cases, the maximum capacity the maximum output of the plant during the period is taken.

Figure 49



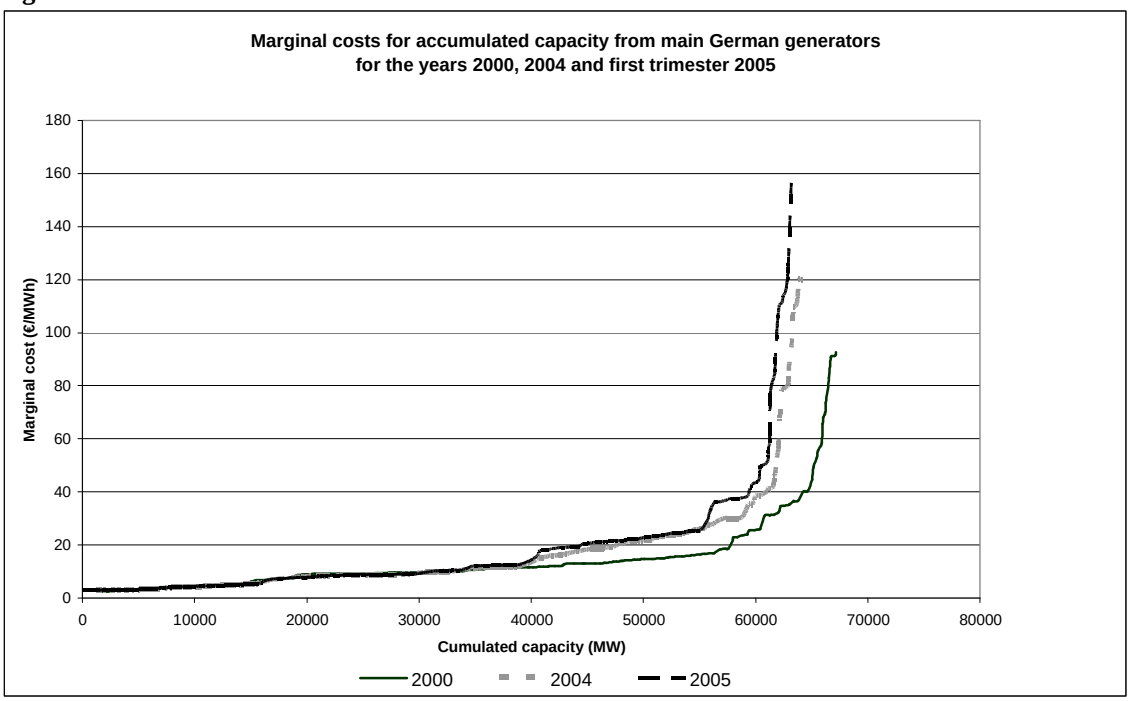




Source: Energy Sector Inquiry 2005/2006

Note: Some corrections have been made to the values of the marginal costs of certain plants to protect confidentiality, but it still gives a fair and representative picture of the actual situation.

Figure 50



Source: Energy Sector Inquiry 2005/2006

(418) As regards the shifts to the left of the merit curve over the years, the evolution of the portfolio of the main generators has been studied. It is interesting to note that the total generation capacity of the four main German generators decreased between 2000 and early 2005 by 4166MW (addition of 1350MW of capacity, and retirement of 5516MW of capacity). This is likely to have an adverse effect on the balance of supply and demand. Furthermore, out of all the plants which have been retired, most of the capacity retired (3753MW) had low variable costs. This had an impact on the merit curve. At the same time – according to Eurostat - there was an increase in overall demand in Germany from 2000 to 2004 of approximately 5.5%.

(419) Similar graphs have also been prepared for France. However these graphs cannot be reproduced as there is one main operator and the graphs would reveal its costs.

Conclusion

Customers have little trust in the functioning of wholesale markets. They suspect market manipulation on the spot and forward markets by large generators to be the main reason for recent price increases. However there are a number of other factors that might explain price increases that require further investigation.

Most wholesale markets have remained national in scope. The level of concentration in generation has remained high in most Member States giving generators scope for market power. The level of concentration in trading markets is less striking than in generation, particularly when analysing shares of operators on yearly forward products. The level of concentration on spot markets reflects more closely the level of concentration in generation, although at a lower level. When analysing who determines the clearing price at certain power exchanges it appears that there is scope to influence prices for operators in Italy, Spain and Denmark. The situation on the French, Dutch and German exchanges will be further assessed.

When analysing whether there is scope to withdraw physical capacity, it appears that load factors have increased over time in Germany suggesting higher efficiency levels and a tighter supply/demand balance. Significant generation capacity – most of it with low marginal costs – was retired in Germany despite slowly increasing demand. Also, certain plants with rather low marginal costs did not operate fully at all times. Further investigation is foreseen for the subsequent phase of the sector inquiry to disentangle the different reasons for price increases.

II.2. Vertical foreclosure and vertical integration[217]

(420) Vertically integrated electricity companies have traditionally been active in generation, network and retail activities. This chapter assesses the effects of this vertical integration. It starts with vertical integration of generation and retail activities and continues with vertical integration of network and supply activities. The sector inquiry confirms that both forms of vertical integration, whilst also bringing about certain economic benefits, have adverse effects for the liberalisation process. The magnitudes of these adverse effects are empirically assessed.

(421) Exclusive long term contracts may also result in vertical foreclosure. They have similar effects to vertical integration of generation and retail activities, as independent suppliers have (almost) no access to uncommitted generation and independent generators cannot supply electricity directly to the wholesale market. This will also be assessed.

II.2.1. Vertical integration between generation and retail activities

II.2.1.1. Introduction

(422) Vertical integration of generation and retail within the same group reduces, all other things being equal, the need to trade on wholesale markets. In turn, this can lead to a reduction of liquidity of wholesale markets. In a market without any vertically integrated companies, all electricity will necessarily be traded between generators and suppliers. In contrast, when all companies are vertically integrated, each vertically integrated group in the sector would meet (part of) its respective demand from final customers with own generation capacity and so would have less need to enter into wholesale transactions[218].

(423) Lack of liquidity can have many negative effects, such as: high volatility of prices, which increases costs for hedging (this can be an important barrier to entry) and a lack of trust that the exchange price reflects the overall supply and demand balance in the wholesale market (reduced reliability of the price signal).

(424) A lack of liquidity may also initiate a vicious circle by creating further incentives to vertical integration because operators do not want to rely on the wholesale market for their electricity supply. New entrants face higher risks when markets are volatile and consequently may not be able to match, at least not in the short run, market offers from their vertically integrated competitors and may only be able to attract capital at higher costs. Similarly, incentives to integrate vertically may result from balancing markets where the regime foresees an economic penalty for imbalances. In such cases, incentives for self-balancing (i.e. to vertically integrate) also exist. Thus, vertical integration limits exposure to volatile wholesale markets and balancing markets.

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217 The title was chosen in order to ensure consistency with the gas part. Contrary to gas the chapter mainly deals with vertical integration.

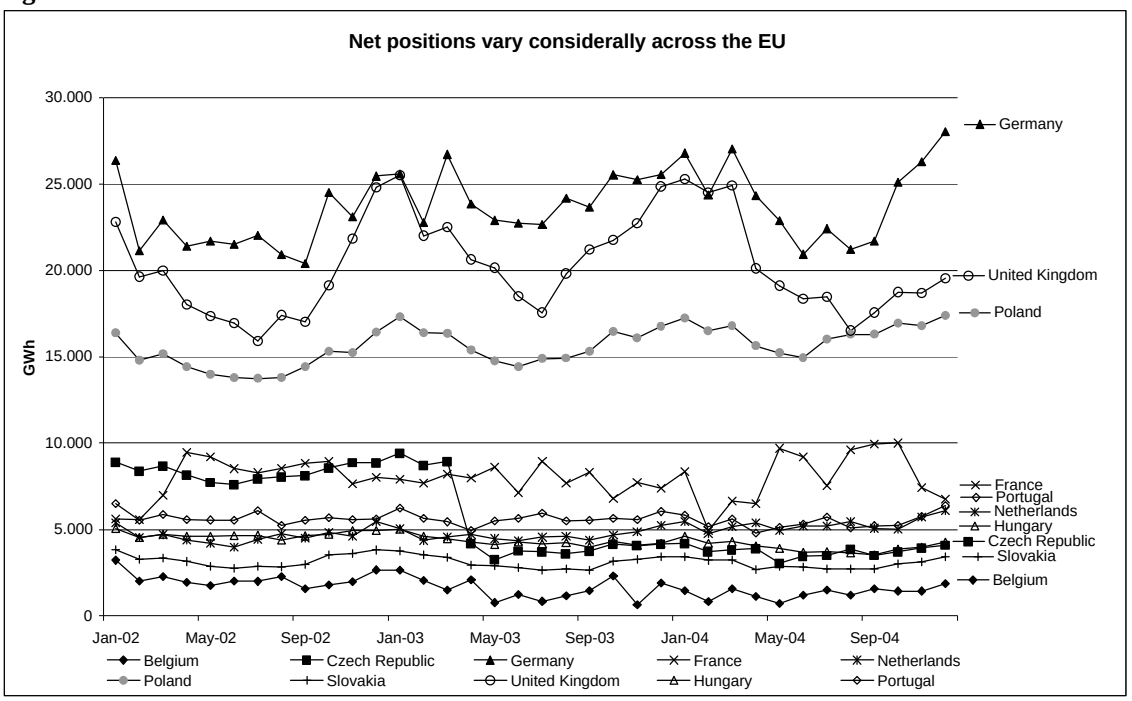
218 Vertically integrated companies continue to have incentives to trade on the wholesale markets, in particular to optimise their generation portfolios. A vertically integrated company that owns the generation capacity to produce all the electricity needed to cover its customers requirements will benefit from buying instead of producing electricity if the wholesale market electricity price is lower than the short run marginal cost of the last generation unit in the merit order of its own generation capacity.

(425) Cross-border entry in electricity markets is facilitated to an important degree if entrants do not have to enter as vertically-integrated companies acquiring simultaneously generation capacity and a customer port folio, but can choose to enter as a supply company or generation company. This reduces the risks and costs of entry. However, this is only possible if a liquid wholesale market exists. Liquid wholesale markets are therefore key for the erosion of incumbent's market power.

II.2.1.2. Comparison of net positions

(426) An undertaking can have a long or a short position, meaning that it, respectively, produces more electricity than is required to supply its retail customers or, less. In both cases a company will have to trade[219] in order to balance its position. The sum of long and short positions ("net positions") of all market participants represents the minimum amount of sale and purchase transactions that must be concluded in order for all short and long positions to clear.[220]

Figure 51



Source: Energy Sector Inquiry 2005/2006

(427) Figure 51 shows that the aggregated net positions vary significantly from Member State to Member State. At one extreme there is the German market with some 25 TWh/month of positions that need to be closed. At the other extreme there is Belgium, where this volume has been below 2 TWh/month for most of the period analysed. It must be noted

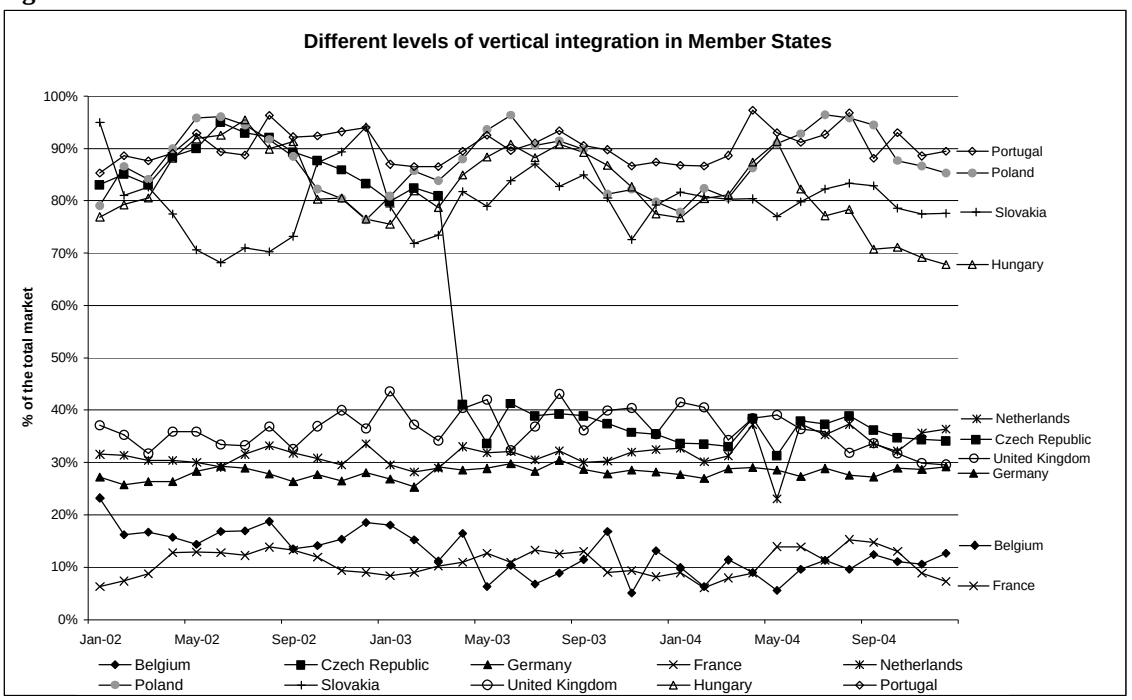
219 The analyses here cannot be directly translated to the manner in which contracts are traded (OTC, power exchange, bespoke bilateral contracts) or the time horizon over which contracts are traded (a given long or short position can be closed immediately before gate closure or any time before.)

220 The design of certain wholesale markets, in particular the Spanish organised market OMEL and to a lesser extent the Italian organised market, GME and Nord Pool result in vertically integrated companies trading all or part of the their generation output through the (organised) wholesale market only to purchase subsequently on the same market the amounts needed for their retail operations. For this reason, the analyses performed in this chapter are not pertinent for these market places.

that the existence of the French VPP programme contributes strongly to liquidity on the French market. Indeed, the auctioned 6000 MW capacity translates into about 3.5 GWh/month.

(428) To demonstrate the real extent of vertical integration between generation and retail per Member State, the figures on net positions have been compared with the total size of respective national markets (see Figure 52). The inquiry reveals that in countries such as the Czech Republic, Netherlands, Germany and United Kingdom, the positions that need to be cleared by trading electricity represents 25-40% of the market. In Belgium and France, this percentage is substantially lower.

Figure 52



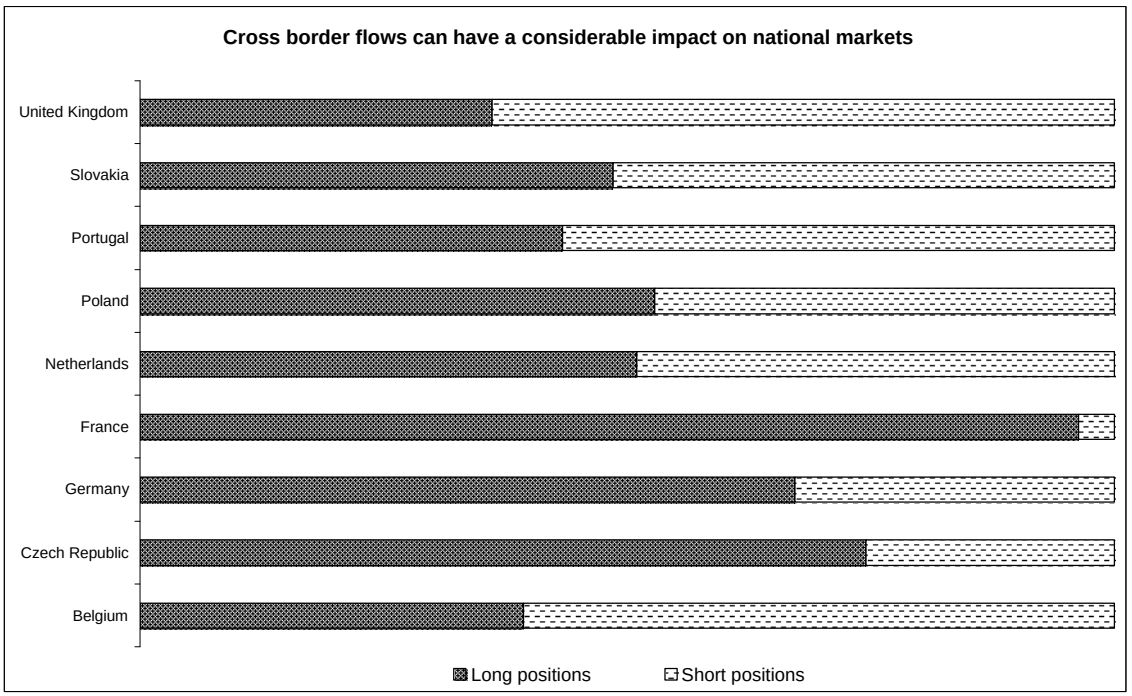
Source: Energy Sector Inquiry 2005/2006

(429) In Poland, the positions to be cleared by trading almost equal the total size of the Polish market, i.e. hardly any generators were selling to final customers. This is however primarily due to the Government's previous policy not to allow vertical integration. The same comment can be made as regards the markets in Hungary and Slovakia, where generation companies are, in general, not active at the retail level (for further comments on these markets see below). For Portugal, the picture is disturbed due to the existence of the single buyer at the wholesale level.

(430) In a closed system, where neither imports nor exports take place, one would expect to observe that the total amount of long positions equals the total amount of short positions. In a liberalised market with cross border flows this equilibrium no longer exists. However, undertakings in the exporting countries need to have overall larger positions because (a part of) this energy will flow to foreign customers. For the importing countries, the opposite is true. In many instances, this theoretical pattern is confirmed by the Figure 53. The pattern is visible in countries like France and the Czech Republic, which are large exporters, or Belgium, where substantial quantities of energy are sourced from abroad. On the other hand, some of the existing discrepancies in Figure 53 can be

explained by the fact that the Commission inquiry did not cover entities falling below certain thresholds.[221]

Figure 53



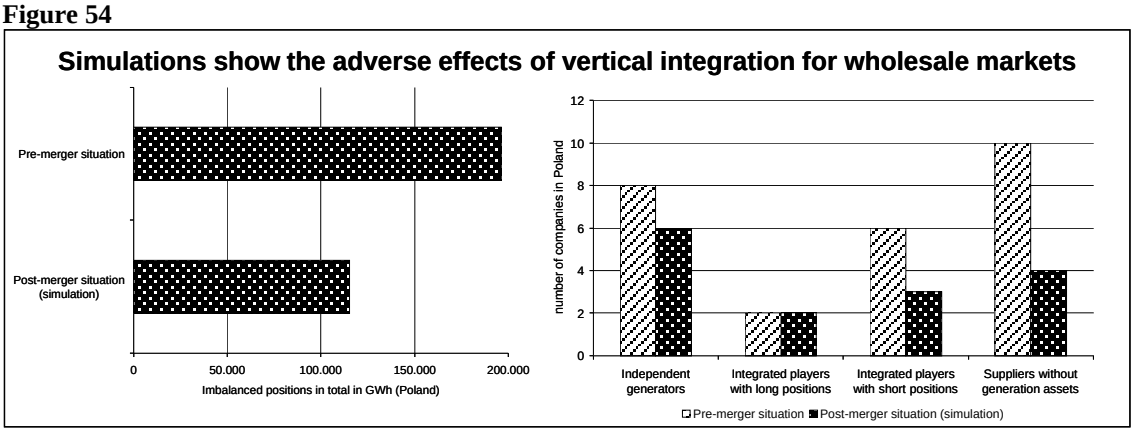
Source: Energy Sector Inquiry 2005/2006

(431) The impact of vertical integration on the net positions can be demonstrated by the Czech example. In 2003 the Czech incumbent, CEZ, acquired control over five of the seven retail companies active at the time. The integration of long (CEZ) and short positions (retail companies) within the same group led to a 40-50% drop in the net positions. On the other hand, the widely held belief by market participants that the drop in wholesale market liquidity in the United Kingdom is related to an increased vertical integration could not be confirmed by this analysis.

(432) The current discussion in Poland about the envisaged vertical integration is another interesting example. It shows that that the level of net positions would drop dramatically (40%) if the planned restructuring around the two largest groups active predominantly in generation goes ahead (see Figure 54).

[221] Suppliers with the annual sales to final customer below 1TWh were not obliged to reply to the questions relevant for this chapter. This in particular means that small retailers in countries like Germany (for instance, smaller 'Stadtwerke') or small independent generators from the UK are not included in the study.

Figure 54

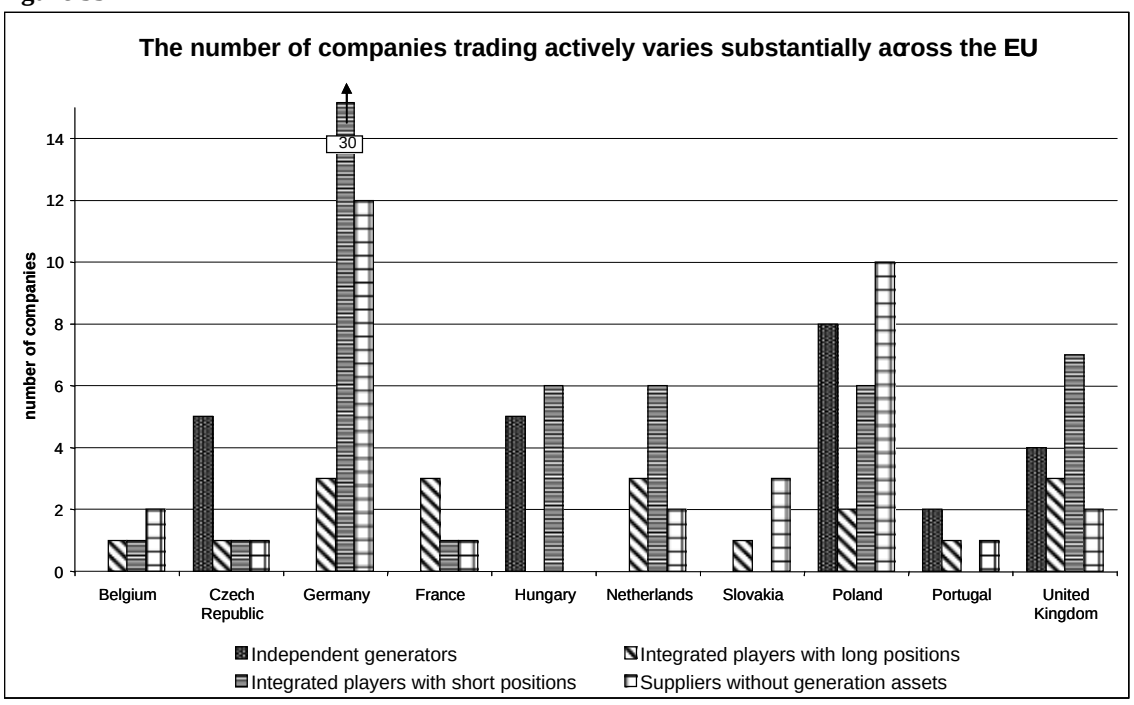


Source: Energy Sector Inquiry 2005/2006

II.2.1.3. Market participants

(433) Vertical integration not only reduces the overall volumes of net positions but may also have an impact on the number of actively trading companies and the size of long or short positions of the remaining active participants. This is important because, as a general rule, it can be said that the more actively trading players on the supply and demand side of the electricity wholesale market the more liquid the wholesale markets. Moreover, non-physical or financial players are, all other things being equal, more inclined to participate in markets with higher numbers of physical participants.

Figure 55



Source: Energy Sector Inquiry 2005/2006

(434) Figure 55[222] provides a first indication how entrants might evaluate the risks that they would be exposed to when entering a market by assessing the number of established generators and suppliers operating with short or long positions in the market. From Figure 55 it may be deduced that the situation in the UK is relatively favourable, whilst for Germany the situation is less advantageous for new suppliers, in particular due to the lack of independent generators.

(435) The likelihood that an undertaking has an interest in increasing electricity prices on spot markets also depends on whether it is long or short as a group. A group that is normally short has to source part of it own supplies from the electricity wholesale markets. Therefore, its generating branch has limited incentives to increase artificially wholesale prices as the company as a whole would not benefit from such a strategy. Figure 55 illustrates that, ultimately, the number of companies in a given market that may have incentives to raise prices above the competitive level is fairly limited[223].

(436) An even better indicator for new entrants to assess their risks when entering new markets is the "concentration levels" in net positions, in other words an analysis that not only takes into account the number of players that are short or long, but also the degree to which they are long or short. In this respect it goes without saying that a high degree of concentration in long positions is not a favourable condition for competitive wholesale markets. A high concentration in short positions is also not conducive to competitive markets although the impact of 'buying power' may be of less immediate concern from a pure competition point of view.

(437) For the purpose of calculating the concentration levels, indices based on sums of squares[224] have been calculated on total production and retail sales as well as the long and short positions of market participants. In almost all cases, the indices calculated on the basis of market positions have higher values than the respective indices calculated on the basis of generation or retail shares (see Figure 56). On the supply/long positions side, the most striking is the effect of this analysis in Belgium and Slovakia. It must also be noted that this analysis affects strongly the German situation. On the demand/short positions side of the market, the effects on the Czech, French, Dutch and Portuguese[225] markets stand out. Furthermore, it should be noted that due to the capacity auctioned under the VPP, the index calculated for long positions in France dropped considerably.

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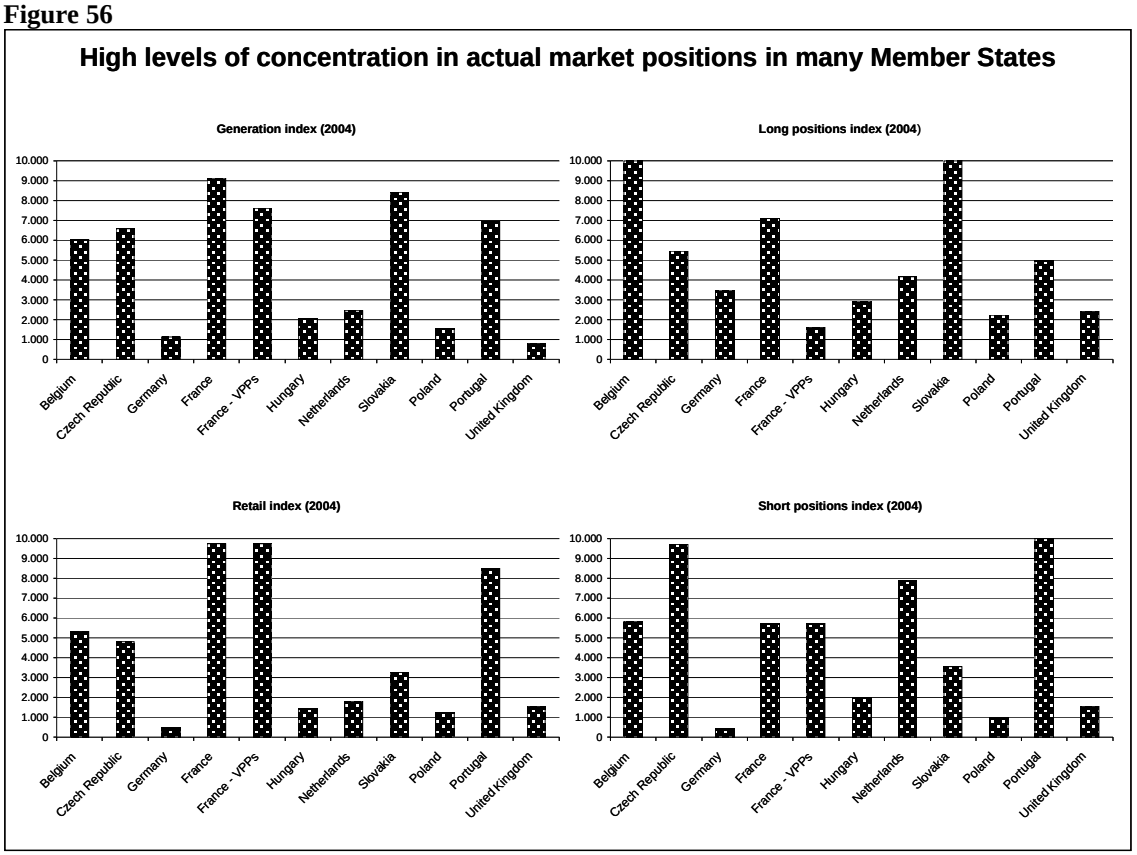
222 Figure 55 does not include suppliers with the annual sales (to final customers) below 1TWh and those of independent generators which have less than 250MW of capacity.

223 This observation depends on downstream contractual relations. The disincentive for vertical integrated companies to use market power in spot markets disappears if retail prices are largely dependent on short-term wholesale prices. However, although spot market indexed supply agreements exist, the sector inquiry shows that contracts with final customers normally have a fixed price. Moreover, no strong link between wholesale prices and those for final consumers can exist where retail prices for non-eligible customers remain regulated.

224 The mathematical algorithm used is the same as in the Herfindahl-Hirschman Index ('HHI index'). Indices have therefore the well-described mathematical properties of the HHI index and can take values from 0 to 10,000, where the latter value indicates that all "observations" are attributed to one source. The term 'HHI' has however been avoided in the main text as the indices are here used in a context where they are usually not applied. Moreover concentration and therefore the HHI index is not a very appropriate indicator for the electricity sector, where, for reasons explained elsewhere, market power can exists at lower levels of concentration then in other industries. Having said that, the figures presented here can certainly provide guidance about a Member State's relative position. For the use of HHIs in the context of competition law application, see the Guidelines on the assessment of horizontal mergers under the Council Regulation on the control of concentrations between undertakings, (OJ C 031 , 05/02/2004 p.5-8) which provide some guidance as to the meaning that can be attached the value of the index.

225 As regards Portugal, the present situation can be explained by the existence of the single buyer at the wholesale level.

Figure 56



Source: Energy Sector Inquiry 2005/2006

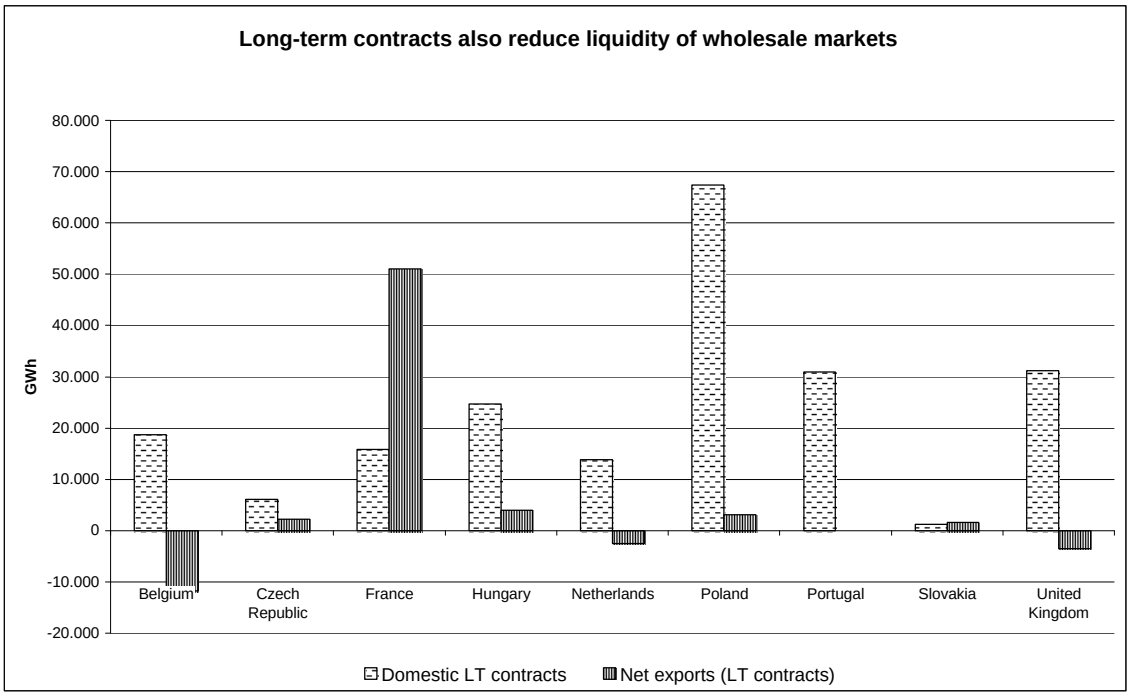
II.2.1.4. Long term power purchase agreements

(438) Long term power purchase agreements (PPAs) are another factor which may affect the volumes that are traded on a regular basis on wholesale markets. Clearly, electricity sold under longer term contracts[226] is also traded. But it has only a limited effect on the price formation process on electricity wholesale markets. In certain countries PPAs are believed to be among the main causes for the low volumes of electricity traded on the wholesale markets. The effects of such agreements were therefore analysed for a selection of countries (see Figure 57).

(439) First of all, it must be noted that not just the existence but also the nature of long term contracts plays a role here. Long term contracts between parties with opposite market positions in the same Member State will always reduce the amount of open long and short positions that need to be closed by wholesale market trading. Import and export contracts however will add or reduce the amount of electricity that is available for trading in a given Member State. Import contracts may therefore mitigate the effects of domestic contracts whereas long term export agreements may aggravate them. In the table below these distinctions are therefore analysed. In particular the Belgian and Dutch markets, considering their size, benefit from imports under long term contacts, mitigating the effects long term contracts may have on these countries. In France, the opposite is true.

226 For the purposes of this analysis, long term contracts were taken to mean contracts of a duration longer than three years and/or that are tacitly renewed.

Figure 57



Source: Energy Sector Inquiry 2005/2006

(440) In France the bulk of long-term contracts are export contracts, which further increased the impact of the domestic contracts. As such a large proportion of potentially traded volumes in France are apparently unavailable for the price formation process, the volumes auctioned under the VPP remain the only significant source of liquidity on this market.

(441) In Portugal, Rede Eléctrica Nacional ('REN') is the single buyer at the wholesale level. It purchases electricity mainly on the basis of long-term 'PPAs' signed with the domestic generators. This energy is sold to non-eligible clients connected predominantly to the distribution network of the EDP group. As long as the present situation prevails, the scope for wholesale trading in Portugal will remain very limited.

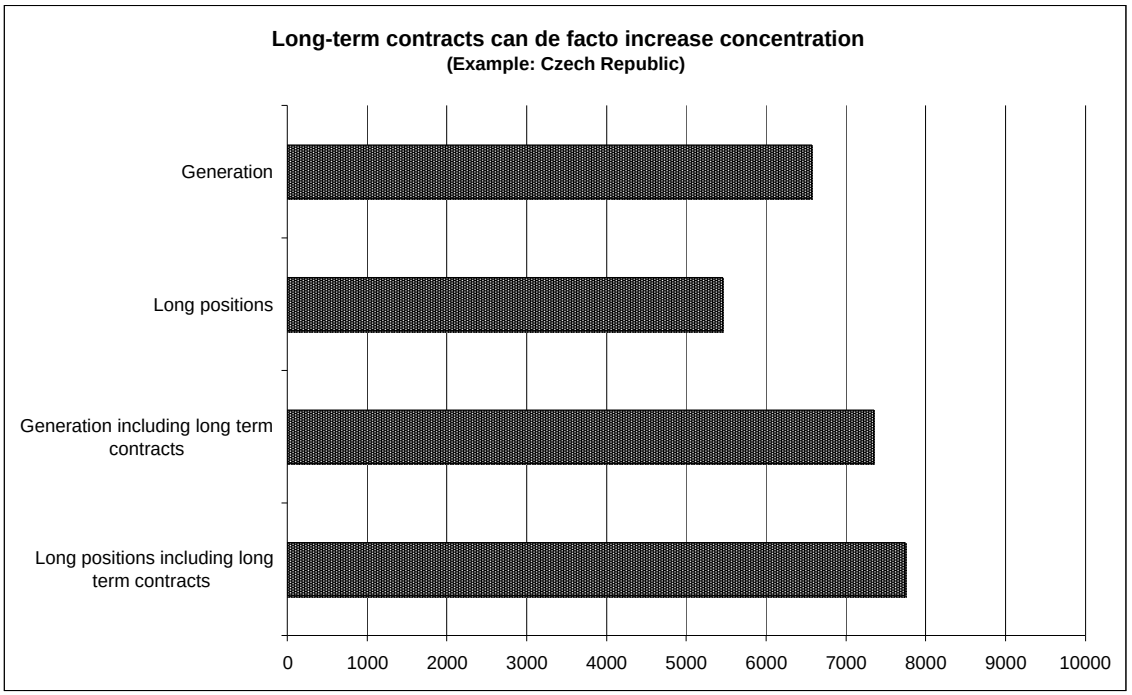
(442) In Poland, the long-term arrangements have predominantly a domestic character. A large number of long-term contracts exist, which were signed mainly in the 1990s between generators and the former national incumbent company, Polskie Sieci Energetyczne ('PSE'). PSE resells this energy to the local distribution companies, who are under obligation to buy each year from PSE a certain percentage of their own sales to non-eligible customers. The fact that power is sold on a long term basis to the incumbent downstream operators means that the relatively favourable picture drawn above as regards volumes available for wholesale trading must be qualified. Even if the degree of vertical integration in Poland stays for the time being very low, 'PPAs' restrict severely the volume of electricity that contributes to the price formation process. Hence, they may well constitute a significant barrier to the development of the Polish wholesale market, even if the currently discussed vertical integration should be abandoned.

(443) A similar situation exists in Hungary, where Magyar Villamos M•vek ('MVM') is the public utility wholesaler and acquires electricity by means of long-term PPAs that is subsequently sold to the local retailers. The Hungarian PPAs cover the vast majority of the country's electricity needs (see Figure 57), which may have effects on wholesale

trading similar to, or even going further than, those described above in the context of the Polish wholesale market.

(444) Potentially traded volumes appear to be less affected by the long-term contracts signed in countries like the Czech Republic or United Kingdom. However, in the former case, such a conclusion may be partly misleading. The Czech PPAs were concluded between the vertically integrated incumbent and independent generators, and their impact was further upstream. Consequently, although these contracts do not immediately affect the volume of electricity that needs to be traded they do affect the number and degree of parties with long positions and add to the already high degree of concentration at the generation level, as is shown by Figure 58.

Figure 58



Source: Energy Sector Inquiry 2005/2006

II.2.2. Vertical integration between supply and network activities

(445) Effective access to the existing network is considered indispensable for competition to develop. This is due to the fact that the network generally constitutes a natural monopoly, that is uneconomic to duplicate.

(446) A company active in electricity generation or supply that also owns transmission or distribution network assets may, however, have an economic interest in using its monopoly position as network owner to prevent or hinder competition in other areas of the value chain. This can happen in many ways such as: raising rivals' costs, price squeezes, withholding essential information and by providing the information only to affiliated companies. All of these practices distort a level playing field.

(447) It is to limit the risk of such behaviour from occurring that the Electricity Directive contains unbundling rules for transmission and distribution networks. The transmission system operator ('TSO') must be independent at least in terms of its legal form,

organisation, and decision making from other activities not relating to transmission. For distribution system operators ('DSO') the rules are similar. However, Member States are not obliged to implement fully the unbundling rules until July 2007. They can also decide not to impose unbundling on distribution companies that have less than 100.000 customers. Unbundling requirements for gas and electricity companies are essentially the same. To avoid repetition, reference is therefore made to the Chapter on vertical foreclosure in the gas part for a more detailed description of what fully implementing the rules entails.

(448) As regards TSOs most Member States have by now implemented the Electricity Directive's requirements for unbundling. Approximately half of them have gone further than the legal obligations and implemented forms of ownership unbundling. As regards distribution system operators, compliance is less advanced[227]. It is true that Member States only have to comply fully with the unbundling requirement for DSOs by 2007. However, a significant number of Member States still have not introduced accounting and management unbundling. Management unbundling was supposed to be implemented by 1 July 2004 whereas accounting unbundling was already required by the first electricity directive of 1996 and had to be implemented by 19 August 1999 by most Member States[228].

(449) It is interesting to note that the conduct discussed in more detail below concerns without exception TSOs and DSOs that have, even if unbundled in accordance with the legal requirements, remained part of a vertically integrated company. Indeed, unbundling measures may render discriminatory practises in the exploitation of the network monopoly more difficult, but do not eliminate the incentives for vertically integrated companies to engage in such conduct. The experiences of full ownership unbundling suggest that it significantly changes the behaviour of the network undertaking: fully unbundled Transmission System Operators ('TSOs') and Distribution System Operators ('DSOs') will focus on optimising the use of the networks.

II.2.2.1. Vertical integration between generation and the transmission network

(450) Article 20 of the Second Electricity Directive lays down the requirements for non-discriminatory access to networks at regulated tariffs. Refusal of access is only possible in case of capacity constraints and must be duly substantiated. Two types of access refusal can be distinguished. Access for potential generators which want to inject their electricity into the grid and access by supply companies, which want to use the net to supply customers.

(451) The first phase of the sector inquiry focussed primarily on the most blatant forms of refusal of network access. Various categories of respondents were requested to report on applications for network access and their treatment. For this report, which deals primarily with wholesale markets, the main focus was grid access for generators. However the report also looked into concerns raised by supply companies (see below).

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227 Source: Communication from the Commission to the Council and the European Parliament: 2005 Report on the Implementation of the Gas and Electricity Internal Market

228 See Art. 27 of Directive 96/92/EC of the European Parliament and of the Council of 19 December 1996 concerning common rules for the internal market in electricity. (OJ L 027 30/01/1997 p. 20, - 29).

(452) The actual number of network access applications by owners of new generation assets was relatively low during the period investigated, (2000 to 2005). In fact, during this period only few investment projects in generation capacity were undertaken and so only a few applications for network access. With this qualification, it is fair to say that blatant refusals for access to networks are apparently rare. This does not mean however that the access to networks is unproblematic. Indeed, a number of respondents reported practises that hindered network access in various ways.

(453) In this respect it is important to underline that network operators can only refuse access to their networks if no or insufficient capacity exists. However, despite the legal obligation to motivate such refusals, the existence, location, and degree of congestion is often not transparent. Respondents in Belgium, Ireland, and Germany claimed that it was impossible to verify whether and to what extent the congestion that was claimed to exist by the network operator was real.

(454) When constraints exist in the network, applicants can often only be connected if they are ready to compensate the network operator for the costs of reinforcing the net, measures that have allegedly be introduced by certain vertically integrated TSOs. Costs for reinforcing networks can be substantial when compared with the overall investment in generation capacity and may render the project uneconomic.

(455) Evidently, a lack of transparency as regards network constraints combined with the obligation on applicants to contribute to network reinforcement creates considerable leeway for vertically integrated companies to raise their rivals costs for bringing new capacity online or even to make this *de facto* impossible without an outright refusal of network access. In principle it is a task of national regulatory and competition authorities to address these issues.

(456) Nonetheless the Sector Inquiry confirmed that in a Benelux country a project to build generation capacity was abandoned solely because compensations to remedy capacity constraints rendered the project uneconomic. Allegedly, no insight was however provided by the TSO as to the causes of this congestion. The generation branch of the TSO was competing with the applicant on the same project. Similar allegations have been made against a German TSO as well as a regional network operator.

(457) Often the works related to building new network connections can only be undertaken by the network operator itself. Evidently, a vertically integrated network operator has no incentive to make attractive offers for building network extensions and reinforcements that will serve its competitors. Indeed, concrete examples from Ireland suggest that costs for network connections by the network operators were significantly, (between 17 and 51%) higher than to earlier connection offers or offers to execute the building works made by third companies. Repeatedly respondents made calls for rendering the building of network extensions and reinforcements contestable, i.e. providing the applicant for a network connection with a choice to contract construction work with a third party. A network operator's ability to raise costs for its rivals would then be curtailed by the existence of competing bids[229].

[229] Experience in the UK has shown that, in order for this to function properly, arrangements have to be made to ensure that DSO's provides technical information concerning the point of connection (needed to design the network extensions) and design approvals in a non-discriminatory manner. (See for instance, SP Manweb – Decision to accept

(458) Supply companies also complained about problems with respect to access to transmission networks. They mentioned in particular problem relating to interconnectors and the provision of information (as described in more detail below in the chapters concerning market integration and transparency). Concerns were also raised with respect to allegedly excessive access tariffs, which would raise competitors cost, but the regulatory oversight foreseen in the Second Electricity Directive should help addressing these concerns. Finally reference is made to the issues set out in the next section dealing with the distribution networks. The issues raised there apply *mutatis mutandis* to transmission networks.

II.2.2.2. Vertical integration between supply and distribution system network

(459) In the framework of the Sector Inquiry, DSOs provided information on the new connections to their networks during 2004 and, among these, the percentage of connections that concluded a supply contract for electricity with any of the supply companies that were affiliated to the DSO. The interest of looking at new connections lies in the fact that these customers are probably least affected by switching costs and, therefore, represent those most likely to switch electricity supplier.

Table 22

Even new customers conclude supply contracts with the supply branch of the DSO	
% of new connections contracting with a supply company affiliated to the DSO	**Member State**
97,5% - 100%	France, Poland, Slovakia, Luxembourg, Greece, Ireland, Estonia
95% - 97,5%	Austria, Germany, Spain
90% - 95%	Italy
< 90%	Netherlands, United Kingdom

Source: Energy Sector Inquiry 2005/2006
Note: The figures in this table cannot be compared with those published in Commission Communication of progress in creating the internal gas and electricity market, COM (2005) 568 and technical annex (SEC(2005) 1445) as the latter are cumulative and use different customer categories.

(460) Even if the figures in Table 22 should be taken with some caution, it is clear that among those end-consumers able easily to choose another supplier, the vast majority conclude contracts with a supply company affiliated to the DSO to whose network the customer is connected. Clearly, even in this category, rates are very low in most Member States. Only in the UK, and to a lesser extent, the Netherlands, do customers choose suppliers unaffiliated to the DSO to which it is connected.

(461) Low switching rates can be due to various factors. Indeed, in the chapter on prices below it will be discussed how the co-existence of regulated tariffs with market based prices may eliminate probably the most important incentive to switch supplier: price. The low rates reported here for France may well be attributed to this factor. Here it is emphasised that in view of these low switching rates, any barrier, even those that do not immediately

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the Gas and Electricity Markets Authority to accept commitments pursuant to section 31A(2) of the Competition Act 1998 of 27 October 2005.

appear to be significant, may nonetheless have significant effects on an entrants' ability to acquire customers. It is therefore very important that switching procedures work properly and do not impose barriers to customer switching.

(462) In a number of Member States, however, substantial problems have been reported with respect to the exchange of customer data needed for switching. In particular, information needed for connection and billing purposes was not provided within the statutory deadlines or not at all, or was simply wrong in a significant number of cases. Such problems have been reported for many countries, including Finland, Spain, Italy, the Netherlands, Belgium, and Germany. Such problems may be inevitable to a certain degree during a transition to liberalised markets, especially in the mass market segments. However, these problems appear to remain as yet unresolved in Belgium and Germany.

(463) Many German respondents reported very heavy administrative procedures, information exchange protocols and payment conditions, so onerous in certain cases that they appear designed to increase switching costs. In Germany, procedures of a voluntary nature existed that were claimed to be inadequate and, in addition, widely disregarded by DSOs. The legislation that was recently adopted in Germany provides powers to the German energy regulator to impose data exchange procedures and protocols. Negotiations are currently underway to finalise a number of procedures and protocols that should improve this unsatisfactory situation. The German regulator intents to render these procedures and protocols obligatory by formal decision for all market participants.

(464) Even if rules exist, however, they may not be sufficient. Most Member States have legislation on, for instance, the maximum duration of switching procedures and the respective responsibilities of parties. Such rules also exist in Belgium. However, contractual relationships are geared towards the interest of the network monopolies in ways that effectively render non-compliance without any consequences for DSO and shift the associated costs and risks to suppliers. As a result, even if statutory rules exist, much metering data in Belgium is still communicated later than the statutory deadlines or is wrong. Many Belgian respondents complain and have substantiated that for a significant number of connection points no metering data is received before the statutory deadline. The Flemish regulator now seeks to extend the liability for the DSO by introducing a flat rate financial compensation to suppliers if statutory deadlines are not respected.

(465) Respondents have also expressed significant concerns about discriminatory conduct in switching procedures. In Belgium and Germany, but also Finland and Austria, there are allegations about preferential information for affiliated supply companies. Repeatedly, respondents complain that affiliated supply companies approach customers with improved offers when their intention to switch is reported to the network branch. Examples have been provided where companies appear to have deliberately withheld historical consumption data to companies competing with their supply affiliates. In Belgium, DSOs representing approximately 80% of all connections have subcontracted operational matters to a subsidiary of the incumbent. The latter manages these operations on the same IT systems that are used by its supply affiliate which therefore has privileged access to information on the customers of its competitors. Over 2006 some structural improvements are expected. Information advantages can also be abused in other ways. Late or even no announcements of changes on network charges to competing suppliers also unduly increase administrative costs and commercial risks for competitors. Such practices have been reported in Belgium and Germany.

(466) German, Polish and Czech respondents also report cases where network related charges were increased when a customer switched or where, which amounts to the same, customers were not invoiced the entire network charges due as long as the customer was supplied by the supply company affiliated to the DSO.

(467) German and Portuguese respondents mention practises rendering it difficult if not impossible for customers that are new to the network to be supplied by parties other than the supply company affiliated to the DSO. These practices may be particularly harmful as they concern customer that may be more easily acquired by entrants.

(468) Inadequate unbundling also maintains the incentives for vertically integrated companies to raise costs for competitors. Respondents have provided detailed information on a very substantial number of German distribution network companies that are said to cross-subsidise supply activities with revenues from (monopoly) network charges. The German regulator recently acquired powers to set appropriate network tariffs which may remedy this situation.

(469) The fact that of the approximately 150 supply companies that entered the German market when customers became eligible in 1999, only a handful have survived until now was attributed by a market participant to the damaging impact of the various practices on the German market reported above.

(470) In more general terms it can be said that unbundling measures may render discriminatory practices in the exploitation of the network monopoly more difficult, but do not eliminate the incentives for vertically integrated companies to favour the affiliated supply branch in network issues. Indeed, it must be noted that the conduct described above concerns without exception TSOs and DSOs that have remained part of a vertically integrated company. Moreover, it regularly concerns DSOs and TSOs that are already unbundled in accordance with the requirements in the Electricity directive[230].

(471) Respondents to the questionnaires therefore often argued that changing DSO's and TSO's incentive structures by introducing ownership unbundling would be the preferred solution to address the issues. A number of respondents from Belgium (where vertically integrated and ownership unbundled DSOs coexist) for instance substantiated that the DSOs that are ownership unbundled perform significantly better in facilitating competition[231] than those that are still part of a vertically integrated company.

[230] Two of the three TSOs referred to are unbundled in accordance with the Second Electricity Directive. Six out of the ten Member States from which allegedly unfair conduct by DSOs was reported have already completely transposed the unbundling requirements for DSOs.

[231] Belgium is transposition of the Second electricity Directive has not postponed the implementation of legal unbundling for DSOs until 2007. Similarly Belgium did not make use of the 100.000 connections threshold to exempt smaller DSOs from the unbundling requirements. For more details see : Newbury (2005) Electricity Liberalisation in Britain: The quest for a satisfactory wholesale market design. The Energy European Special Issue, IAEE, 2005.

Conclusions

Vertical integration of generation and retail reduces the incentives to trade on wholesale markets. This might lead to a drying up of wholesale markets. Illiquid wholesale markets are a barrier to entry as they are characterised by higher price volatility. Volatile wholesale markets might oblige new entrants to enter as a vertically integrated generator and supplier, which is more difficult.

The degree of vertical integration between generation and retail differs significantly between Member State. In most Member States there are few companies with long positions leading to high "levels of concentration". VPPs (auction of electricity) assist in some Member States (e.g. France) to improve the level of concentration. Long term power purchase agreements (PPAs) have similar effects to vertical integration.

According to respondents', vertical integration of supply and network (transmission and distribution alike) reduces the economic incentives for the network operator to grant third parties access. In the views of many respondents the existing rules on legal unbundling do not ensure that vertically integrated companies do not engage in practices favoring their supply affiliates to the detriment of their competitors.

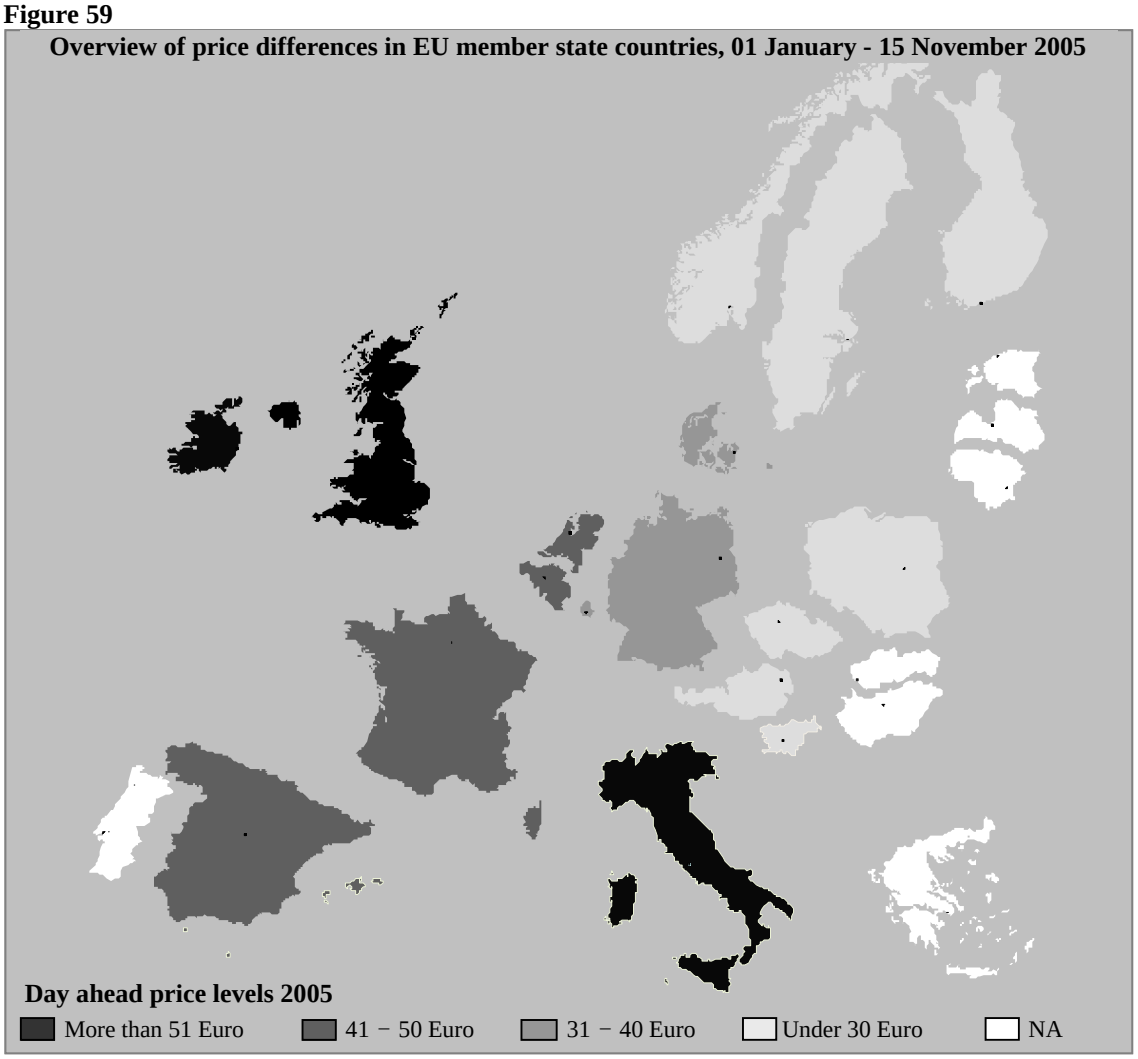
With respect to transmission networks, a number of respondents complained about significant costs to connect new power plants to the network. No means exists to verify whether claims of congestion or costs for network reinforcements are valid. With respect to the distribution networks, respondents reported amongst other things inappropriate switching procedures, a lack of Chinese walls between network and supply branches and discriminatory access tariffs.

II.3. Market integration

II.3.1. Introduction

(472) Interconnectors are essential for market integration. Through interconnectors generators and suppliers on both sides of the border are exposed to competition. Imports should drive prices down to the level of the minimum required cost to serve the required electricity in all EU Member States. However, today prices differ substantially between geographical region in the EU. This is illustrated in Figure 59.

Figure 59



Source: platts, Power exchanges.

(473) Imports should also play a role in eroding the market shares of major generation companies in wholesale electricity markets. However, in most Member States the incumbent's market shares have remained high. The need for imports is even more important knowing that market entry by new players who started supply or generation activities in countries in which they were previously not present was hardly observed in EU Member States during the liberalisation.

(474) The Sector Inquiry leads to the preliminary findings that the lack of electricity market integration[232] mainly results from:

- insufficient interconnecting infrastructure between national electricity systems,
- insufficient incentives to improve cross border infrastructure,
- inefficient allocation of existing capacities, and
- incompatible market design (e.g. differences between balancing regimes, nomination procedures, differences in opening hours of power exchanges) between TSOs and/or spot market operators.

II.3.2. Institutional setting

(475) Before liberalisation, integrated companies, who where responsible for supply of customers and their electricity grids, decided to connect their grids through cross border links (interconnectors) in order to be able to assist one another in case of temporary shortages caused by unexpected high demand or generation outages. For continental Europe the UCTE-synchronous[233] area includes 22 countries (also non-EU members). Another synchronous zone is the NORDEL area in Scandinavia. Additional so-called DC-links (direct current-links) connect (other) grids further.

(476) Today the role of interconnectors has changed significantly. In many Member States participants can access interconnector capacity in order to trade on wholesale markets and hence potentially benefit from price differentials between regions. In order to facilitate the use of cross border capacity by participants several procedures have been introduced. This topic will be examined later.

(477) The load pattern in the EU integrated synchronized network results from production and consumption locations, and net topology. Transactions made by generators, traders, suppliers and consumers result in electricity transports from one region to another. Due to the characteristics of electricity (explained earlier) demand and supply have to be balanced at all times. Introduction of a set of administrative rules, most importantly requesting players in the market to report in advance which (contractual) transactions they want to carry out, should enable the TSOs to manage commercial transactions and physical flows in a secure manner in the high voltage grids.

(478) The TSOs' main task is to provide a secure and stable grid facilitating the integrated electricity market. This includes activities to balance the equilibrium between supply and demand in their so-called control area and between control areas of other TSOs. Ensuring that the TSOs perform their work at minimum cost is commonly the task of regulators who are part of the institutional setting in the EU. Clearly, any change in the (administrative) rules may alter the extent to which cross border trade in the EU is possible.

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232 At this stage cross border market power issues have not yet been assessed.

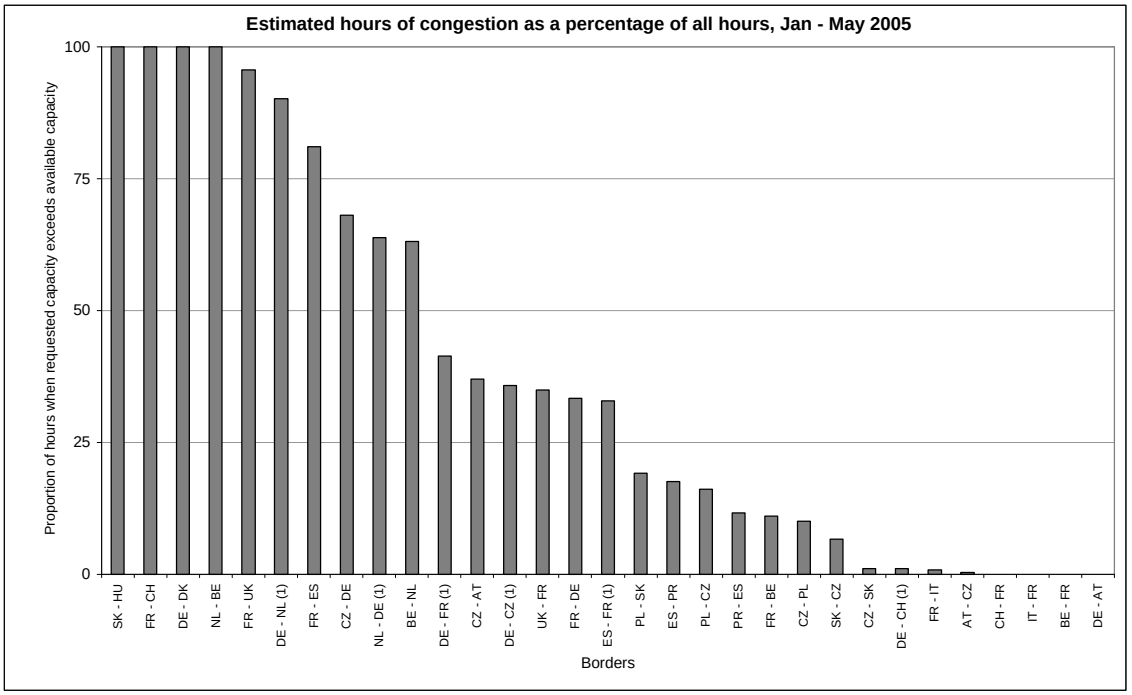
233 Synchronous meaning that all members of UCTE work on the same 50 Hz frequency.

II.3.3. Insufficient interconnecting infrastructure

(479) Since the liberalisation of the electricity markets the need for interconnector capacity has increased substantially. This is of particular importance for players who have entered other markets and become active in cross border trade. Their arbitrage activities constitute buying (in low price regions) and selling (in high price regions) of electricity in different markets. As a result they shifted the traditional generation pattern in the grid. Moreover the generation pattern was also changed due to investments in generation technologies such as wind power. This injects more variable power flows into the grid compared to for instance a coal fired power plant - caused by changes of the wind speed (possibly reducing available cross border capacities). More interconnection is needed to facilitate companies extending their activates into other regions outside their traditional areas in order to increase competition.

(480) Demand for interconnector capacity at many borders increased and often exceeds the available transmission capacity. This congestion is illustrated in the subsequent Figure 1 per border. The bars show number of hours (sorted in ascending order) per border reported by TSOs when capacity requested exceeded the available capacity as a percentage of all hours in the period January – May 2005. This situation can be independent from the physical flows in the grid. The bars represent a specific direction.

Figure 60



Source: Energy Sector Inquiry 2005/2006.
Note: Most TSOs reported congestion per interconnector, but some TSOs reported congestion aggregated over several interconnectors between adjacent markets. In some cases the reported data deviate per border between TSOs. This means that the involved TSOs do not have a common clear statement whether the requested capacity exceeded the available capacities or not. This suggests that the approach to capacity allocation is not sufficiently coordinated and needs improvement. (1) Refers to an average of more than one interconnector between two adjacent borders.

(481) Figure 60 reveals that almost all borders are congested to some degree, except a small number of borders such as e.g. IT to FR, BE to FR and DE to AT. Congestion depends of

course on the direction since there is a clear incentive for traders to deliver electricity from low to high price regions. Some borders are congested in all hours during the first five months of 2005. Examples are the interconnectors from SK to HU, DE to DK, NL to BE and FR to CH.

(482) Congestion has increased on most borders. Table 23 compares the percentage of congested hours in the first five months in 2004 with 2005. Congestion increased on almost 60 percent of the listed borders. The cause of increasing congestion has to be further studied. It is likely that persistent price differences between Member States markets cause congestions. The relative marginal costs e.g. from CO2 emissions might also reduce congestion and unforeseen changes in wind speed cause unforeseen flows that might reduce the capacity available and increase congestion.

(483) At some borders the increase of congestion has been dramatic. For instance, from the Germany to France congestion has increased from almost 0% in January 2004 to 100% in the month May 2005. Figure 61 shows this development of congestion per month between January 2003 and May 2005. Further investigation is required to explain the differences in the level of congestion between the period before and after January 2005.

(484) The consequence of the substantial and increasing congestions on interconnectors between Member States is that many electricity markets are separated from each other. As a result imports are limited and their ability to counter market concentration in national markets and exert competitive pressure on (dominant) generators is reduced and consumers pay more for their electricity than strictly necessary.

(485) The questions that arise from the above are:

- Is existing interconnector capacity used efficiently?
- Are incentives to invest in new interconnector capacity set properly and what are other obstacles to increasing interconnection capacities?

II.3.4. Level of interconnector capacity

(486) Investing in the expansion of interconnector capacity is one way to lower congestion on the borders between Member States. At present the level of interconnectors as a percentage of installed capacity is listed in Table 24.

(487) The Barcelona Council 2002 set a target for (import) interconnector capacity of at least 10% of production capacity per Member State by 2005. Using the Sector Inquiry data the current percentages for some MS have been calculated. The results (average 2004 NTC value as a percentage of installed generation capacity) are shown in Table 24. It confirms earlier reporting by the Commission that several countries, such as Italy, Portugal, Spain, Ireland and UK, do not meet the 10% threshold. However, meeting the "Barcelona" target does not necessarily result in resolving congestion and concentration in generation. For instance, the Dutch interconnector remains congested though the import capacity is 17%. Neither does this target resolve concentration in generation. For instance, in Denmark which has a relatively high level of interconnection still has, high levels of concentration in generation and scope for the exercise of market power as shown in the chapter Concentration and Market Power.

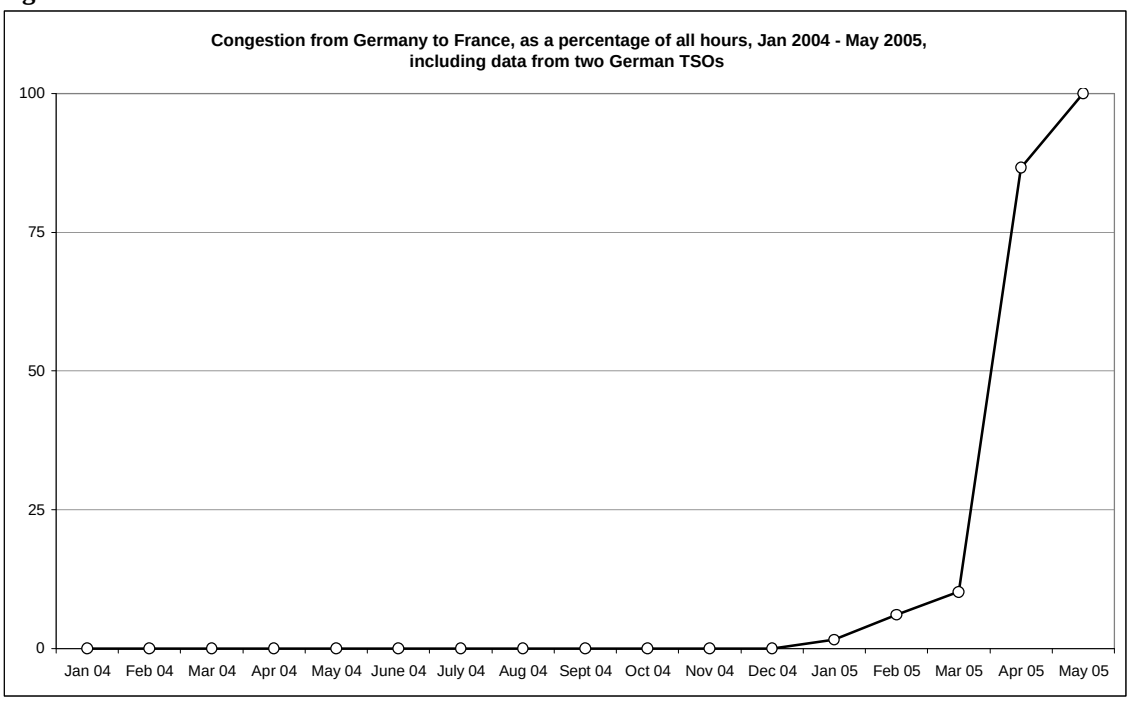
Table 23

Hours with congestion as a percentage of all hours (selection of borders)		
Border	**2004** Jan-May	**2005** Jan-May
SK --> HU	100,0	100,0
FR --> CH	100,0	100,0
DE --> DK	99,3	100,0
NL --> BE	96,4	100,0
FR --> UK	94,6	95,6
DE --> NL (1)	87,9	90,1
FR --> ES	34,6	81,1
CZ --> DE	69,2	68,0
NL --> DE (1)	62,9	63,9
BE --> NL	63,3	63,1
DE --> FR (1)	0,0	41,3
CZ --> AT	0,0	37,0
DE --> CZ (1)	30,0	35,7
UK --> FR	31,5	35,0
FR --> DE	48,4	33,3
ES --> FR (1)	30,0	32,8
PL --> SK	0,0	19,1
ES --> PR	7,8	17,5
PL --> CZ	15,8	16,1
PR --> ES	26,7	11,7
FR --> BE	30,4	11,0
CZ --> PL	0,2	10,1
SK --> CZ	1,4	6,6
CZ --> SK	2,1	1,1
DE --> CH (1)	0,0	1,0
FR --> IT	0,7	0,8
AT --> CZ	0,0	0,3
CH --> FR	0,0	0,0
IT --> FR	0,0	0,0
BE --> FR	0,0	0,0
DE --> AT	0,0	0,0

Source: Energy Sector Inquiry 2005/2006.

Note: Hours when requested capacity exceeded available cross border capacity as a percentage of all hours. The arrows indicate the direction per border, in some cases reported by different TSOs. (1) Refers to an average of more than one interconnector between two adjacent borders.

Figure 61



Source: Energy Sector Inquiry 2005/2006.

(488) Availability interconnector capacity is related to the performance of TSOs who are responsible for system integrity in their control area and hence calculating the NTC (Net Transport Capacity) for import and export. Figure 62 illustrates that the values have remained almost unchanged over the last 30 months. The movements of the curve relate to summer and winter periods. NTC values may also change as a result of production factors such as changes in wind speed, outages and (unforeseen) maintenance of power plants or internal grid outages. In addition consumption factors, such as changes in demand, may affect the level of NTC values.

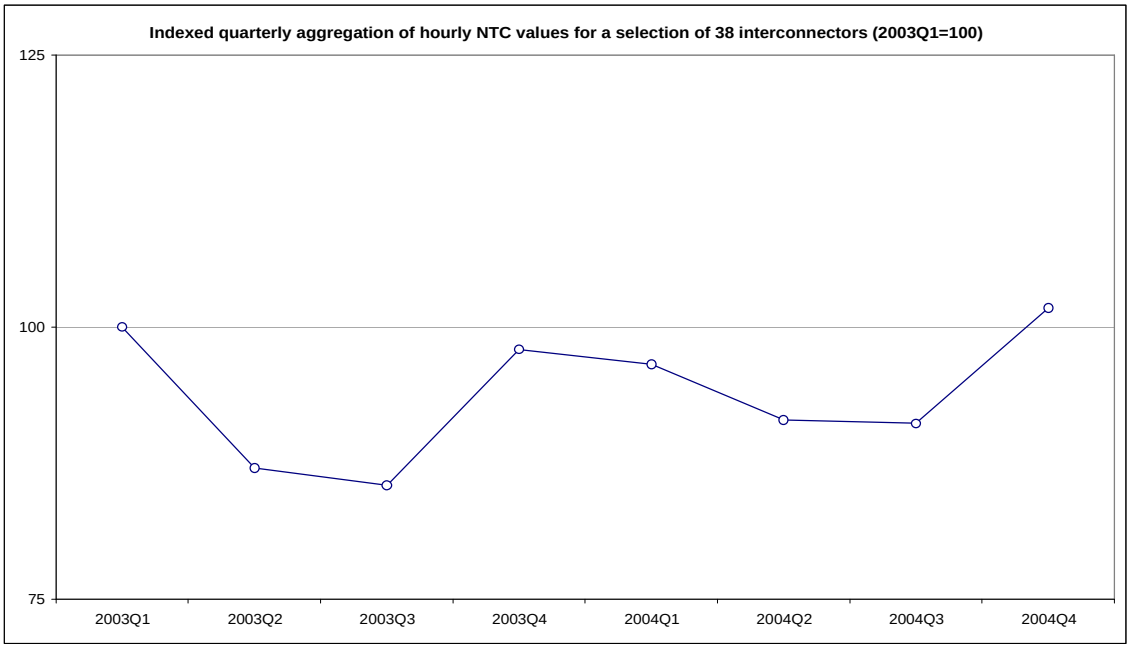
(489) NTC-levels may be affected by the way TSOs manage grid congestion in their control area. At this stage no assessment has been made of TSO's behaviour regarding the treatment of congestion on internal lines and interconnectors. Table 25 shows at first glance that such an assessment may not be required since only Austrian and Italian TSOs state that they have lines in their grid that suffer from congestion for at least 10% of all hours. Other TSOs reported that they have congested lines, though not meeting the threshold of 10 %. It is unclear at this stage if TSO's relieve congestion on their internal lines at the expense of lower cross border capacity, and if so if it is done for sound cost efficient reasons.

Table 24

Average hourly NTC relative to installed generation capacity for a selection of countries, 2004	
Country	**%**
UK	2
Italy	6
Spain	6
Ireland (1)	6
Portugal	9
Poland (1)	10
Greece (1)	12
Finland (1)	14
France (2)	14
Germany (3)	16
Netherlands (1)	17
Czech Republic (1)	23
Austria (1)	24
Belgium	25
Sweden (1)	29
Hungary (1)	38
Slovakia (1)	39
Denmark (1)	50
Estonia (1)	66
Slovania (1)	68
Luxembourg (1)	90

Source: Energy Sector Inquiry 2005/2006, UCTE and ETSO.
Note :(1) NTC values from ETSO used for calculation
(2) For Italian-French NTC value is estimated
(3) For Polish-German NTC and Czech-German NTC is estimated.

Figure 62



Source: Energy Sector Inquiry 2005/2006.

Table 25

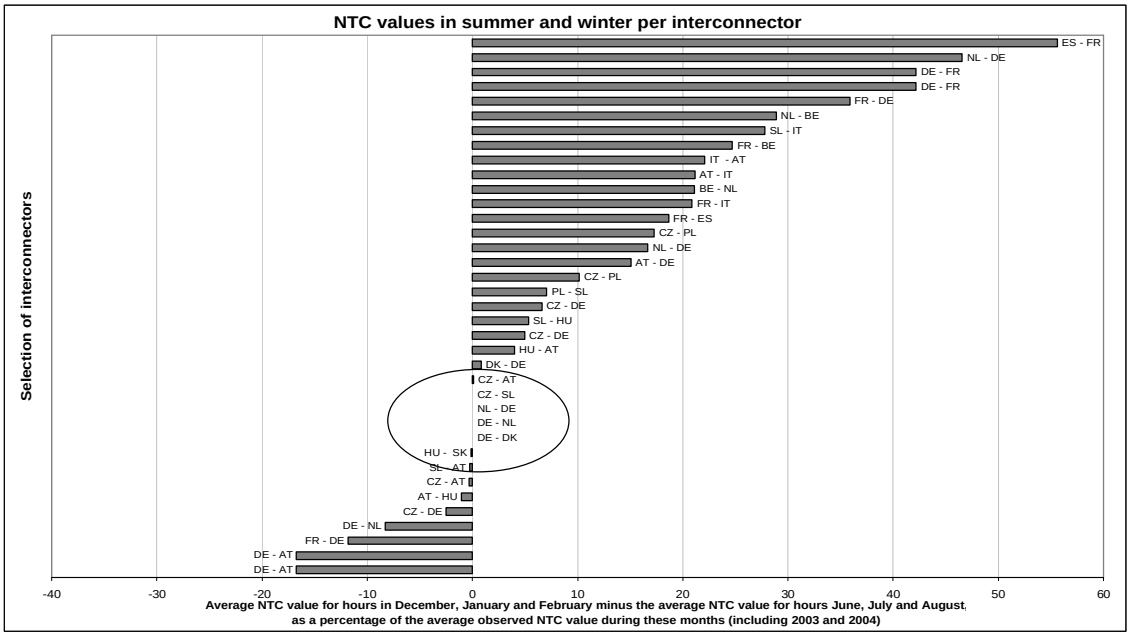
Congestion of lines other than interconnectors, selection of TSOs	
Country	**Number of lines congested for more than 10% of the hours in one calendar year during 2003 - May 2005**
Austria	none
Austria (1)	4
Denmark	none
Denmark	n.a
France	none
Germany	none
Germany	none
Germany	none
Germany	none
Italy (2)	5
Netherlands	none
Spain	none
United Kingdom	none

Source: Energy Sector Inquiry 2005/2006.
Note: Some countries appear more than once because they have several control areas.
(1) 2003.
(2) April 2004 – March 2005.

(490) During relative cold months, ignoring other factors, NTC values may increase compared to relatively warm periods due to the physical characteristics of electricity wires. Several TSOs explain this in their answers to the questionnaires. Figure 63 demonstrates that the performance of TSOs to maximise the amount of cross border capacity delivered to the

market differ substantially between TSOs. For instance the difference in the NTC value for the Spanish – French border between winter and summer month exceeds 55 percent. This is positive for the market as during relatively cold periods more capacity is available for cross border trade. However, at some borders (marked area in Figure 63) the NTC values seem to be insensitive to temperature changes and remain at the same level throughout the year.

Figure 63



Source: Energy Sector Inquiry 2005/2006.
Note: Differences between the average Net Transport (NTC) in relative cold and warm months relative to the average NTC value in % - 2003 and 2004. In some cases borders appear two or three times in Figure 63 which is due to the fact that each TSO reports on export and import NTC values per interconnector.

(491) The results for some interconnectors in the marked area of Figure 62 are difficult to explain. They seem to suggest that there was very little difference in the level of NTC values between summer and winter. The results of negative bars (below the marked area in the figure) are also difficult to explain since they show that during winter periods the NTC values are lower than in summer periods. However, it is important to note that there are also other factors than outside temperature that affect NTC levels. As is explained above, local generation and consumption events play an important role determining NTC levels. These may have a stronger effect than the temperature. However, the figures illustrate that the differences between the performances of the TSOs are substantial. Clearly, on borders where high price differences persist the need to optimise the level of available interconnector frequently is more important than elsewhere.

II.3.5. Incentives for TSOs to build more capacity

(492) A precondition for building additional interconnector capacity is that incentives to expand the net are properly set by regulators who set the (regulatory) framework. Incentives for building merchant lines (unregulated lines) may arise from estimated future revenues primarily reflecting the absolute price differences between adjacent geographical wholesale markets. Market design changes or new generation investments are hard to predict over a long period. The replies to the Sector Inquiry also confirmed

that planning procedures for building new interconnectors are complicated, not least for environmental reasons.

(493) TSOs, who in the past had a monopoly on building additional interconnectors, may also invest in new or additional interconnection (regulated lines), and hence it is important that TSOs have correct incentives. Table 26 shows that many TSOs obtain congestion revenues[234] and that these revenues are not fully invested on projects to increase interconnector capacity. Article 6 (6) of the Regulation 1228/2003 states that revenues resulting from the allocation of congested interconnector capacity shall be used for: (a) guaranteeing the actual availability of the allocated capacity; (b) network investments maintaining or increasing interconnector capacities, or; (c) as an income to be taken into account by the regulatory authorities when approving the methodology for calculating network tariffs, and/or in assessing whether tariffs should be modified.

Table 26

Congestion revenues and total investments in interconnectors during 2001 - 2005 in mln-euro		
TSO	**Congestion Revenues (2001 - 06/2005)**	**Interconnection Investments (2001 - 06/2005)**
A	200-300	25-35
B	0-20	0-10
C	80-150	0-10
D	200-300	0-10
E	200-300	50-100
F	80-150	0-10
G	20-80	0-10
H	80-150	80-150
J	0-20	10-40
K	0-20	10-40
Total	**1000-1300**	**200-300**

Source: Energy Sector Inquiry 2005/2006.
Note: Excluding spending on congestion relief.

(494) The table shows that only about one quarter of the congestion revenues is used to build new interconnections or to reinforce existing grid elements. This result from the Sector Inquiry demonstrates that incentives need improvement.

(495) According to answers from TSOs these revenues are mainly used to reduce national grid tariffs. Since the existing interconnections were financed in the past by tariffs paid by the local consumers it could be justified to allocate the welfare resulting from auctions to these consumers. On the other hand consumers would also profit from increased generation efficiency gained from additional cross border trade and enhancement of the markets. That being said, it should be clear that based on current (cross border electricity) regulation TSOs are allowed to spend congestion revenues on lowering transmission tariffs for electricity in their control area.

(496) In the Sector Inquiry some TSOs also provided information on recent studies on new interconnection lines. Most of these studies conclude that building a new line is a difficult and lengthy procedure and in some cases the impact on the available interconnector

[234] Congestion revenues refer to the additional revenues (e.g. auction proceeds) the TSOs receive due to congestion for the interconnectors.

capacity would be low compared to the efforts required. This is partly due to the fact that in many cases increasing the level of cross border capacity also requires substantial internal grid reinforcements.

Congestion revenues of German TSOs in 2001 to 2005 and use of the revenues

In the period 2001 to 2005 three German TSOs managing interconnectors generated congestion revenues of [400-500] million Euro. Of these revenues only [20-30] million Euro were used to reinforce/build new interconnectors (one TSO said that it does not know how much of the investment into the net had the effect of reinforcing interconnectors). All TSOs maintained that the remaining revenues were used to reduce the transmission tariffs. One TSO declared that the extension of a 380 KV line with a length of 50 km and a capacity of 1400 MVA costs [1-10] million Euros. The building of new lines or subsea cables is significantly more expensive.

II.3.5.1. Utilisation of existing interconnector capacity

(497) The congestion mechanisms to allocate interconnector capacity play an important role in market integration. The word (congestion) mechanism refers to a set of actions and measures that are applied to handle network access in the presence of congestion. Table 27 lists from the questionnaires the most commonly used mechanisms and divides them into market based and non-market based methods. Table 27 also explains briefly the different mechanisms.

Table 27

Overview of the most common interconnector allocation mechanism	
Not market based, discriminatory and often not transparent methods	**First-come-first-served** (Priority list) Capacity is allocated according to the order in which the transmission requests have been received by the TSO. Starting from the earliest request, all requested amounts of capacity are fully granted until the available capacity is used up. **Pro-rata rationing** All requests are partially accepted so that each applicant is granted a fixed share of his requested capacity amount, the share being equal to the amount of available capacity divided by the sum of all requested capacity amounts. **Retention** A proportion of the available capacity is granted in long term contracts (also) based on grand father rights
Market based and non-discriminatory methods	**Explicit auction** Along with the requested capacity amount, the applicants have to declare how much they are willing to pay for this capacity. These bids are ordered by price and allocated starting from the highest one until the available capacity is used up. Usually the price for the capacity is set to the bid price of the lowest allocated bid. **Implicit auction** Transmission capacity is managed implicitly by two or more neighbouring spot markets: network users submit purchase or sale bids for energy in the geographical zone where they wish to generate or consume, and the market clearing procedure determines the most efficient amount and direction of physical power exchange between the market zones. Hence, separate allocation of transmission capacity is not required, cross border capacity and energy are traded together.

Source: Energy Sector Inquiry 2005/2006.

II.3.5.2. Non market based mechanisms

(498) Mechanisms that allocate interconnection capacity using methods that are not market based, discriminatory and not (always) transparent result in inefficient use of interconnector capacity. This is due to the fact that in contrast to auctions, first-come-first-served, pro-rata rationing and retention do not necessarily allocate capacity to participants that value interconnection capacity the highest. Partly it could be allocated to some who do not value it at all.

(499) Quite a number of questionnaire responses criticize the existence of non-market based mechanism not only because they are not market based and discriminatory, but also because they are often not transparent resulting in unclear allocation and sometimes favouring incumbents. In addition these methods are anyway incompatible with Regulation 1228/2003, but still seem to be practised for certain interconnectors as is shown in Table 28. This table lists the different allocation mechanisms per interconnector through which existing interconnector capacity is commonly allocated to the market – excluding long term contracts.

(500) Table 29 illustrates that a significant proportion of existing interconnector capacity is still allocated on the basis of priority rights or "pre-liberalisation" contracts. These capacity reservations often relate to some of the most congested interconnectors.

(501) From a legal point of view the existing grandfather rights are problematic. The ECJ stated in a recent case (C-17/03, Vereniging voor Energie, Milieu en Water, judgment of 7 June 2005) that a preferential treatment for pre-liberalisation capacity reservations is incompatible with the Electricity Directive 96/92/EC if the Member State concerned failed to request an exemption pursuant to Article 24 of that Directive. Pre-liberalisation contracts may also be assessed under Articles 81 and 82 EC and recently the Commission received requests for guidance on this important issue. Responses from some large energy consumers indicate that they would be interested in booking capacity on interconnectors. However, most customers consider that transaction costs are too high for them to become directly involved in cross-border trade.

(502) It cannot be excluded that long term contracts could result in efficient allocation as secondary trade could in theory employ efficient redistribution means. But the holder of the contract would still profit from the money paid in the secondary market and, more importantly, the conditions to obtain these long term contracts in the past were often not equal. Also it is often not transparent who "owns" the capacity and how long the underlying contracts last. This raises search cost (transaction costs) for any player interested in buying this interconnector capacity, since "secondary capacity markets" remain immature. This raises barriers to entry and may harm liquidity in several wholesale markets. Hence, long term contracts should with certain exceptions be disqualified as a method for allocating scarce interconnector capacity. Recent reports indicate that efforts to dismantle these contracts are in progress. For exemple, the Netherlands have directly reacted to the ECJ decision and the French Regulatory Authority decided not to grant priority rights any more for long term contracts on the interconnection with other EU Member States.

Table 28

Overview of allocation mechanism of the main EU interconnectors - selection	
Allocation mechanism	**Border**
Explicit auction	Denmark - Germany United Kingdom - France Germany - Netherlands Germany - France Poland - Germany Poland - Czech Republic Czech Republic - Austria Czech Republic - Germany Austria - Hungary Austria - Slovenia (1) France - Italy (2) Belgium - Netherlands France - Belgium
Implicit auction	Sweden - Finland Denmark - Sweden
First come - first serve	France - Switzerland France - Spain (3)

Source: Energy Sector Inquiry 2005/2006.

Notes:(1) On this border Slovenia has been exempted from Regulation 1228/2003 (requiring that cross border capacity is to be allocated using a market based method) until 2007. The explicit auction here is just conducted for the Austrian half of the interconnection capacity.

(2) For the French - Italian border there does not exist a joint capacity allocation. The explicit auction is just conducted for the French half of the interconnection capacity.

(3) On the French side export capacity is allocated on a daily basis and in blocks of 25 MW based on a priority list subject to satisfying minimum use factors to maintain the position in the list, and the allocation of import capacity is based on a pro-rata method. On the Spanish side the capacity is shared between bilateral contracts and market transactions and after that implicit auctions organised by OMEL are applied.

Table 29

Long term reservations on a selection of interconnectors, 2005								
Border	France-Spain	Spain - France	France - Italy	Czech Rep. - Austria	Austria - Italy	Czech Rep. - Germany	Poland - Slovakia	Slovakia - Hungary
Current NTC value (1)	[1-1000]	[1-700]	[1-2300]	[1-600]	[1-190]	[1-950]	[1-800]	[1-1000]
Long term contracts as % NTC	60-70%	70-80%	60-70%	60-70%	50-60%	20-30%	40-50%	30-40%

Source: Energy Sector Inquiry 2005/2006.

Note: (1) The NTC values used for percentage calculation represent 2004 data, since for 2005 they were not available for the entire year.

II.3.5.3. Market based methods

(503) On many congested interconnectors TSOs make use of explicit auctions for day-ahead allocations. Examples of interconnectors that are explicitly auctioned are listed in Table 28 and include e.g. NL – DE and FR – UK. This mechanism is considered not to be satisfactory by a number of respondents in the sector inquiry, because it suffers from the time lag between capacity allocation and wholesale market clearance.

(504) Figure 64 focuses on these comments. It shows for each hour in 2004 the spot price differences between the Netherlands and Germany, e.g. APX price minus the EEX price (horizontal axis) and correlates the sum of nominations from Germany toward the Netherlands (vertical axis). Each dot in the figure represents an unique hour with a price difference and the result of the nomination. It reveals that in many hours (40 percent of all observed hours) during 2004 capacity was nominated from Germany to the Netherlands while prices in Germany where higher than in the Netherlands. This result is intuitively not rational since the wholesale electricity price in the Netherlands is typically higher than in the German wholesale market. Such an arbitrage 'mistake' is shown in the upper left area (diagonally marked) in Figure 64. All markers in this area constitute an irrational (economical) outcome. The area in the bottom-right (also marked) also represents irrational outcome.

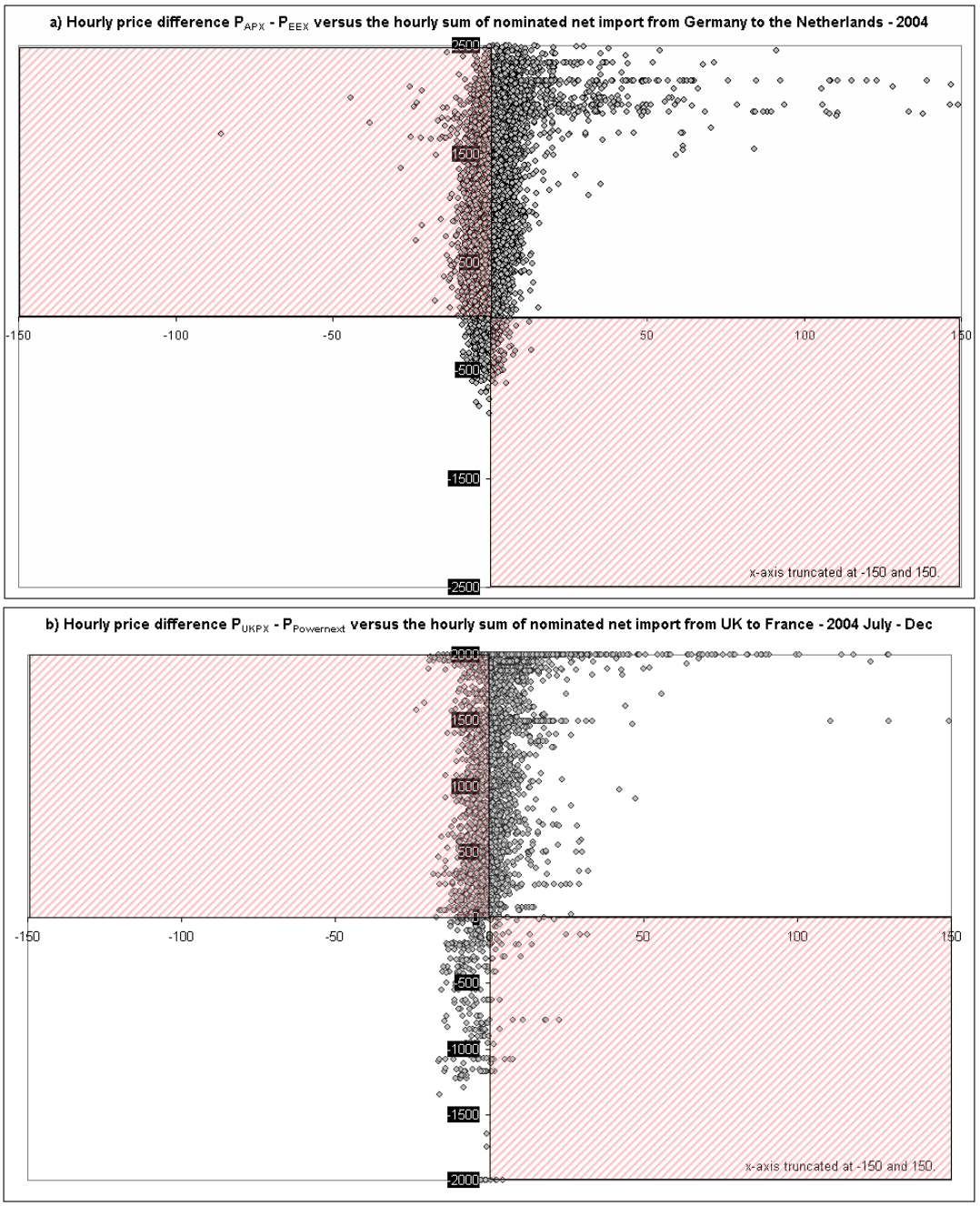
(505) One of the explanations for these economically inefficient outcomes is that the deadline for the day ahead interconnector auction ends before the German (EEX) and Dutch (APX) energy market clears. A similar coordination issue occurs on the interconnector between France and the UK (England and Wales), where the deadline for interconnector nominations occurs after the French (Powernext) energy market clears, while the UKPX (the leading UK power exchange) is open and prior to gate closure in respect of the UK balancing mechanism. The consequence is that explicit auctions do not lead to an optimal use of scarce interconnector capacity.

(506) From the responses from the questionnaires market participants confirm that they face uncertainty due to the fact that they have to place bids based on expected prices. As markets after the day-ahead market are illiquid players cannot easily resell acquired electricity in the market where they initially had bought the electricity, and buy in the market where they would have liked to use the acquired electricity. They would have a preference for that if they had anticipated a positive price difference in an hour between two markets, but after market closure it turns out that the price difference is negative.

(507) In addition, it might be unreasonable for transactions to be nominated in two directions if the price spread between the two energy markets was small, however participants might prefer to transfer electricity from the high to the low prices markets in order to avoid exposure to balancing prices. This is particularly relevant where interconnectors connect relatively illiquid markets.

(508) Due to the arbitrage errors systematically made by the market participants incorrect signals prevail regarding the value of interconnector capacity. This leads to incorrect incentives to attract new investments into interconnector capacity.

Figure 64



Source: Energy Sector Inquiry 2005/2006, ECB Exchange rate Pound vs Euro.

(509) Table 30 shows that the financial loss resulting form underutilisation plus incorrect utilisation (wrong sign nominations) of interconnector capacity is significant per border. For instance, in 2004 almost 50 million Euro was not utilised in the Dutch - German border which is 46 percent of the total value (107 million Euro) of this interconnector capacity. Due to the relatively high Dutch spot price volatility in 2003 the result in 2003 was more than 20 million euro higher. A similar calculation is done for the French-UK border. The results are presented in Table 30.

Table 30

Estimated value of unused cross border capacity (selection) ***in mln. euro***		
Borders	**2004**	**2003**
NL to DE	49,4	70,8
UK to FR	64,4 (1)	…
FR to ES	41,8	140,3

Source: Energy Sector Inquiry 2005/2006.
Note: The estimated amounts are calculated as follows. For each hour the estimated day ahead available import capacity is reduced with nominations. This is the estimated unused capacity. Summed with wrong sign nominations they are multiplied with the absolute hourly spot market price difference. NTC values day ahead used in this figure represent an ex-ante estimation of the seasonal transmission capacities of the joint interconnections on a border between neighbouring countries, assessed through security analyses based on the best estimation by TSOs of system and network conditions for the referred period. (1) Includes July 2004 – May 2005.

(510) Further there remain a few borders where the allocation of interconnector capacity is not carried out according to a harmonised and economic-based mechanism. The French – Spanish border is an example and Table 30 shows that also on this border financial loss is significant.

(511) The result of the above analyses illustrates that, although explicit auctioning is theoretically with perfect foresight an efficient mechanism and it is in practice compatible with Regulation 1228/2003, it has efficiency deficits compared to implicit auctioning. With implicit auctions results of trade are not likely to have economically irrational use of the interconnector capacity as is the case for explicit auctions as demonstrated in Figure 64.[235]

(512) An additional advantage of implicit auctions is that netting, which has not been discussed in this chapter, will become feasible. For instance, on the Dutch – German border import and export capacity is auctioned separately. Hence, introducing implicit auctions may increase the available capacity significantly.

II.3.6. The need for harmonization

(513) One of the key complaints from the respondents in the sector inquiry is that parties involved in arbitrage between borders face important differences between the administrative rules underlying the electricity markets. For instance the imbalance settlement period (for TSOs to balance the market) limits the possibility to alter schedules. These differences in settlement periods result into increased risks and are therefore barriers to trade. The different time periods for which imbalances are settled are shown in Table 31.

[235] In this context is should be mentioned that new important congestion management guidelines are currently being discussed (see http://europa.eu.int/comm/energy/electricity/legislation/doc/congestion_management/cm_guidelines_en_v1.pdf)

Table 31

Different time windows in which imbalances are settled by control area - 2004	
Country, responsible TSO(s)	**Time unit**
Netherlands (TenneT) Italy (GRTN) Austria (APG, TIRAG, VKW-UNG) Germany (EnBW TNG, E.On Netz, RWE TS, Vattenfall ET) Belgium (Elia) Luxembourg (Cegedel)	15 minutes
France (RTE) England & Wales (NGT)	30 minutes
Poland (PSE-Operator) Sweden (SK) Norway (Statnett) Denmark (Energinet.dk) Slovenia (ELES) Spain (REE) Greece (HTSO/DESMIE)	60 minutes

Source: ETSO (2004), DG Comp.

(514) The rules for nominating transactions and the rules relating to changes (if needed) of nominations before gate closure also differ between countries. Because of these differences, nominations for cross border transactions - if possible - require separate administrative procedures per border. Conditions for nominations also differ between countries. These differences increase the complexity for market players to trade across borders and may reduce the scope for competition.

Conclusion

Imports do not yet adequately play their role to counter market concentration in national markets and exert competitive pressure on incumbent operators. Hence consumers may pay more for their electricity than strictly necessary. Important reasons for inadequate market integration include:

- Insufficient levels of cross border capacity,
- Inefficient congestion management methods (including explicit auctions),
- Important differences in rules that manage the electricity markets administratively within and between control areas,
- Long term cross border capacity reservations, partially given under discriminatory conditions, and
- Lack of adequate incentives to invest in additional capacity.

II.4. Transparency

(515) Efficient wholesale electricity markets can bring significant benefits to the electricity sector, in terms of greater operational efficiency, improved signals for investment, greater security of supply, better allocation of risks and increased scope for competition.

II.4.1. Transparency is needed for electricity markets to develop

(516) For efficient wholesale markets to develop it is essential that all market participants have access to the information considered necessary to trade, in particular as regards expected demand, supply and network issues. The sector inquiry confirms, however, that there is a lack of transparency in most Member States. There is a general perception that generation data of incumbents is sometimes first shared with affiliates, which undermines the confidence in the wholesale markets. The inquiry also revealed examples where operators seem to have withheld information regarding generation outages until after markets have closed, which may have allowed them or their affiliates to trade on electricity markets on an unfair basis.

(517) More transparency is needed essentially for three reasons. First the publication of more information would allow all players to take informed action on the markets, which minimises their commercial risks and reduces entry barriers. Secondly it ensures a level playing field by avoiding that certain parties have access to commercially sensitive information (e.g. from generation affiliates), but others do not. If the transparency obligations are not sufficiently strong, some market participants will be able to profit unfairly at the expense of other market participants. Thirdly, lack of transparency undermines the trust in the wholesale markets and with it its price signals as a reliable benchmark.

(518) The need for transparency to promote the development of the wholesale markets is not only the view of the European Commission but has been widely recognised, both in answers to the questionnaires and outside the context of the sector inquiry. The Florence Forum[236] concluded at its September 2005 meeting that "participants also highlighted the need for increased transparency, in view of creating a functioning and fair market".

(519) European Energy Regulators (CEER) emphasise that the transparency of information about the physical situation of the European electric system is one of a number of conditions that must be met to facilitate the development of a single energy market, as specified by the directive of June 26, 2003. Although some initial progress has been recorded in many Member States, the degree of transparency of information about the physical situation of the European electric system remains weak.

(520) Eurelectric stated[237] that "the development [of wholesale electricity markets] must be underpinned by solid involvement by all market participants and by a common body of available information. (…) It is essential that market places fulfil at least the following criteria: (…) provide transparent access to common sets of market information." In the same report it went on to say "another prerequisite for the development of liquid

[236] Conclusions of the Florence Forum of 1-2 September 2005, section 2(d), page 4.

[237] Eurelectric report of June 2005 "Integrating Electricity Markets through Wholesale Markets: Eurelectric Road Map to a Pan-European Market".

wholesale markets is the trust of the market participants in the market. Therefore, market transparency and information exchange in the wholesale markets must be harmonised to ensure that all market participants have the same information at their disposal".

(521) The European Transmission System Operators (ETSO) published a paper on transparency[238] which focuses on the provision of information to TSOs to allow them to manage the network as efficiently as possible. However, in the paper it also states that "ETSO believes that data from generators and market participants is of particular importance to achieving improvements in transparency and facilitating fair and efficient markets". It should be noted in this context that the full implementation of the congestion management guidelines that are currently being adopted should increase transparency as regards cross-border congestion.

(522) The European Federation of Energy Traders (EFET) stated[239] "an efficient wholesale market for power is crucial to meeting the aims of liberalisation and offers the prospect of considerable benefits to consumers. The development of an efficient wholesale market, however, is currently being hindered by the lack of information being released to the market".

(523) Barclays Capital, an important electricity trader, stated in its reply to the sector inquiry questionnaires "information release is the key non-structural measure that could be implemented to improve competition in EU electricity markets. Greater information release would allow participants to understand the underlying supply and demand events that drive prices which in turn facilitates better price forecasts, increased liquidity and hence an increased ability for a wider range of participants to compete to supply customers. Greater information release will also result in better price signals for maintenance, closure and investment decisions which in turn enhances system reliability and security of supply". It further went on to say that "the cost to EU energy consumers of poor information transparency alone is therefore likely to run into tens of billions of Euros". This figure seems very high at first glance, but it represents just over 5 percent of the total turnover in the electricity sector in the EU of approximately €180 billion in 2004 (and with significant increases since).

II.4.2. The risk of collusion does not outweigh the advantages of more transparency

(524) There is a risk that excessive transparency, particularly in an oligopolistic market as many electricity markets are, could facilitate collusion between the major suppliers. However, given the current state of the electricity markets and the low level of transparency in many markets, this does not in practice appear to be a likely at this stage. Indeed, the principal problem at the moment is that the lack of transparency in most markets undermines the development of the wholesale markets. In any case, the risk of facilitating collusion could be reduced by only publishing figures on an aggregated rather than individual basis (at least in advance of trading). Therefore, in the current state of the electricity markets and as long as where necessary information is published to all market participants in an aggregated basis, the risk of facilitating collusion – whilst requiring monitoring - does not outweight the benefits of more transparency.

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238 ETSO paper "List of data European TSOs need to pursue optimal use of the existing transmission infrastructure" of December 2005.

239 EFET Position Paper: "Transparency and Availability of Information in Continental European Wholesale Electricity Markets", July 2003.

II.4.3. The level of transparency varies widely between Member States

(525) Despite the widespread recognition of the need for transparency in order for wholesale markets to develop, the sector inquiry has provided evidence that the level of transparency in the wholesale markets in the EU is not satisfactory. It is also widely divergent. In the context of the sector inquiry national regulators were asked whether adequate information was made publicly available in their Member State on 49 precise issues[240] covering:

- technical availability of TSO network (10 issues covering inter alia frequency and causes of congestion, net and available transfer capacity, prices and physical flows)
- technical availability of interconnectors (11 issues addressing similar issues to those asked regarding the TSO network)
- load (5 issues covering inter alia day ahead and week ahead aggregated load forecasts and actual load)
- balance and reserve power (5 issues covering inter alia demand for balancing power, system balance status and actual use of reserve power)
- generation (production) (4 issues covering inter alia actual generation and outages)
- generation (capacity) (14 issues covering inter alia production portfolios).

(526) 21 national regulators replied. According to the regulators, information is published in the Member States on between zero and 38 of these issues. On average information was published on just under 20 issues. Table 32 shows the range of information published in the Member States according to the regulators.

(527) It can be seen from Table 32 that the markets in which most information is published (eg Nord Pool and the UK) are generally perceived as more competitive than those where little information is published.

[240] The list of 49 issues is attached in annex H.

Table 32

Number of issues for which information is published by Member state	
Member State	**Issues for which information is published (out of 49)**
UK	38
Spain	34
Denmark	31
Finland	30
Sweden	27
Portugal	26
Poland	25
Lithuania	24
Germany	23
Slovenia	21
Italy	20
Hungary	18
Belgium	17
Netherlands	16
Greece	16
France	14
Ireland	13
Austria	12
Slovakia	8
Estonia	1
Latvia	0
Czech Republic	-
Luxembourg	-
Cyprus	-
Malta	-

Source: Energy Sector Inquiry 2005/2006

II.4.4. Market participants not satisfied with level of transparency

(528) In the sector inquiry, suppliers were asked about the information that must be available to trade within acceptable risk levels on electricity wholesale markets. For each of the 49 issues suppliers were asked whether information was made publicly available, and were asked how important this issue was. Table 33 summarises their replies:

Table 33

Suppliers' views on whether information is available	
suppliers saying that "indispensable" information was not available	43%
suppliers saying that "important" information was not available	16%
suppliers saying that "useful" information was not available	25%
suppliers saying that "all useful" information was not available	17%

Source: Energy Sector Inquiry 2005/2006.

In a nutshell more than 80% of market participants are not content with the current level of transparency arguing that indispensable, important and useful information is not made available.

II.4.5. The information that market participants believes ought to be published

(529) At its meeting in September 2005 the Florence Forum considered the need for more transparency. ETSO undertook to provide a list of the data TSOs need to ensure an optimal use of the existing infrastructure. At the same meeting "Eurelectric agreed to provide a list of information that it considers market agents need to have in order to trade efficiently, where possible in co-ordination with traders, power exchanges and customers"[241]. The ETSO paper has been published and the Eurelectric paper is expected to be published in early 2006. It should not only address the question of what information needs to be published but also when (eg in advance, in real time or with a certain delay).

(530) The replies to the sector inquiry indicate the broad types of information that market participants believe should be made public. The questionnaires sent in the context of the sector inquiry to generators, traders and suppliers ("suppliers") asked them to identify how they assess the importance/relevance of different issues to trade. Table 34 summarises[242] their replies (on the same of a comprehensive analysis of the replies to sector inquiry).

Table 34

Importance of information according to suppliers				
	indispensable	**important**	**useful**	**not useful**
TSO network	36.1%	24.5%	34.6%	4.8%
Interconnectors	30.5%	30.8%	30.5%	8.2%
Load	24.8%	32.9%	36.9%	5.5%
Balancing	22.2%	30.1%	38.4%	9.3%
Generation (production)	20.0%	33.5%	32.7%	13.8%
Generation (capacity)	26.7%	29.9%	37.5%	5.9%

Source: Energy Sector Inquiry

(531) Table 34 suggests that for market participants the issues on which information is most important are (in decreasing order):

1. Technical availability of interconnectors
2. Technical availability of TSO network
3. Generation (capacity)
4. Balancing and reserve power
5. Load
6. Generation (production)

(532) It is surprising that generation (production) is stated to be the least important issue. This could be because currently this information is not widely available and so market participants are not used to receiving it. Another possible explanation is that the information is perceived as commercially sensitive by the generators concerned. In this respect it is interesting to note that almost all suppliers who said that generation (production) information was "not useful" were local or regional incumbents, who might be expected to be able to benefit from the refusal to release the information, whilst possibly sharing relevant information between affiliates.

241 Conclusions of the Florence Forum of 1-2 September 2005, section 2(d), page 4.

242 Information on the views of suppliers on the importance of each of the 49 precise issues is attached in annex H.

(533) In a similar vein, some market participants have stated that they should not be required to publish confidential information. Instead they propose that in advance they should only reveal the information to a third party (normally the TSO or a power exchange) who should publish the information in an aggregated form combining similar information from parties in the same position. This would not seem to pose a problem as long as more detailed information on a disaggregated basis was published once the trading had taken place. In any event, there is a strong presumption that as much information as possible should be published, because otherwise market participants possessing market sensitive information would be able to profit from this information. As this profit would be at the expense of other market participants, acceding to the request not to publish this information would increase risks for market participants and confuse the price signals from the market.

(534) It should be noted that in the most liquid and efficient wholesale markets, including in particular Nordpool and the UK, the transparency requirements are high and so commercially confidential information is limited. It should also be noted that in Nordpool (as stated below) market participants with insider information are not allowed to trade until the relevant information has been disclosed to the market. This suggests that if an exemption for confidential information is to be allowed it must be very restricted. It could, for example, be to allow some very sensitive information to be published in aggregated form in advance and the detailed information to be published following an appropriate delay rather than in real time. This would still allow the possessor of the information to benefit from it, but replies to the sector inquiry indicate that even delayed publication of information is of importance to market participants as it allows them to understand price movements in the past and so to model price movements in the future.

II.4.6. Responsibility for publication of information

(535) Responsibility for revealing relevant information should primarily lie on the market or network participant responsible for the relevant activity. For example, generators should ensure that the required information on generation capacity and actual generation is revealed, and TSOs should ensure that the required information on congestion is revealed. However, in some cases, it might be appropriate for a third party to be responsible for the publication of the information. For example, if it was decided that information on generation schedules should only be published in an aggregated form before gate closure then generators might be made responsible for providing the TSO or another third party with their generation schedule and the TSO would be responsible for publishing aggregated figures. This issue should be further considered by the European Commission and the market participants during the discussions on precisely which information should be published and when.

II.4.7. The transparency requirements under EC law

(536) EC financial services rules, in particular the Markets in Financial Instruments Directive (MiFID)[243], the Prospectus Directive[244], the Transparency Directive[245] and the Market

[243] Directive 2004/39/EC of the European Parliament and of the Council of 21 April 2004 on markets in financial instruments amending Council Directives 85/611/EEC and 93/6/EEC and Directive 2000/12/EC of the European Parliament and of the Council and repealing Council Directive 93/22/EEC (OJ 2004 L 145/1). The MiFID allows investment firms, banks and exchanges to provide their services across borders on the basis of their home country

Abuse Directive (MAD)[246] and its implementing rules[247], impose various transparency obligations on financial markets.

(537) The aim of these Directives is to regulate the trade of securities, including derivatives on commodities, and related financial services. Commodity trading, including electricity and gas trading, is generally not covered by these Directives unless it is considered to be trading in derivatives on commodities. Some but not all power exchanges and brokers platforms in the EU are covered by the national rules implementing these directives. For example, in the Netherlands the APX exchange is not seen as falling within the scope of the directives, while Endex[248] is.

(538) Furthermore, the sector-specific rules only impose limited transparency obligations on electricity wholesale markets or their participants.

II.4.8. Transparency requirements under national law or market conditions

(539) In addition to the requirements under EC law, there exist transparency requirements under national law or self-imposed transparency requirements in individual markets (e.g. it can be a condition of trading on the market concerned to subscribe to certain transparency rules).

(540) The following examples from the most important wholesale markets are representative.

- Trading in Nord Pool is subject to regulation both by the authorities in accordance with national law and by Nord Pool pursuant to the private law market conditions. In particular, Nord Pool prohibits insider trading under its conditions to trade on the financial market (although there is no statutory prohibition against insider trading in Norwegian law). Market participants must notify Nord Pool of any insider information, which is defined as "any matters related to the relevant entity's business in the electricity markets that is likely to have a substantial impact on the prices in listed products". This is further specified to include any planned outages or maintenance concerning more than

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authorisation. The Directive also harmonizes the requirements for the provision of investment services and the operation of regulated markets by imposing several pre-trade and post-trade transparency requirements..

244 Directive 2003/71/EC of the European Parliament and of the Council of 4 November 2003 on the prospectus to be published when securities are offered to the public or admitted to trading and amending Directive 2001/34/EC (OJ 2003 L 345/64). The Prospectus Directive lays down several requirements for the prospectus to be published when securities are offered to the public or admitted to trading on a regulated market.

245 Directive 2004/109/EC on the harmonisation of transparency requirements in relation to information about issuers whose securities are admitted to trading on a regulated market and amending Directive 2001/34/EC (OJ 2004 L 390/38). The Transparency Directive covers periodic and ongoing information requirements for issuers whose securities are admitted to trading on a regulated market.

246 Directive 2003/6/EC of the European Parliament and the Council of 28 January 2003 on insider dealing and market manipulation (market abuse) (OJ 2003 L 96/16). The main aim of the MAD is to establish harmonised rules prohibiting market abuse, in particular insider dealing and market manipulation which harm the integrity of financial markets and public confidence in securities and derivatives.

247 In particular Commission Directive 2003/124/EC of 22 December 2003 implementing Directive 2003/6/EC of the European Parliament and of the Council as regards the definition and public disclosure of inside information and the definition of market manipulation (OJ 2003 L 339/70) and Commission Directive 2004/72/EC of 29 April 2004 implementing Directive 2003/6/EC of the European Parliament and of the Council as regards accepted market practices, the definition of inside information in relation to derivatives on commodities, the drawing up of lists of insiders, the notification of managers' transactions and the notification of suspicious transactions (OJ 2004 L 162/70).

248 Endex European Energy Derivatives Exchange operating an electricity futures exchange.

200MW. Participants possessing such information may not trade on Nord Pool until the relevant information has been disclosed to the market by Nord Pool[249].

- In the UK the main transparency requirements are imposed in accordance with the Grid Code and the Balancing and Settlement Code. Compliance with these codes is a condition for obtaining a licence as generator or supplier. Implementation is monitored by the regulator OFGEM. The existing rules require market participants to publish information such as intended generation, contractual positions and outage plans to National Grid Company (NGC), the TSO. Most of this information is circulated to market participants via the internet. NGC also circulates its outage plans to market participants. With respect to unplanned events, participants must provide an oral and written account, the latter within two hours of receiving original notification of the event.

- In Germany it appears that the main transparency requirements as regards trading on EEX are due to national legislation (national competition law and the German Securities Trading Act supervised by the EEX trade monitoring office, the State Ministry for the Economy and Labour in Saxony and the German Financial Supervisory Authority (BaFin)). The TSOs also impose transparency obligations including use of interconnectors and congestion problems.

- In France, the national and EC legislation on market abuse is not applied to Powernext. However, Powernext has inserted provisions into its market rules to prohibit market abuse. Furthermore, the national legislation has recently been amended to grant the regulator the power to carry out surveillance of "transactions carried out on organised electricity markets as well as on the interconnectors"[250].

(541) Experience of enforcement of these rules appears to be extremely limited, with the exception of Nord Pool. Nord Pool has carried out eight detailed investigations since 2000, and in a number of cases found that the rules had been breached. In the UK there have been no formal investigations in the generation market relating to competition law or OFGEM's regulatory controls since 2001 (although there were previous investigations into the pool prices). The Financial Services Authority investigated the trading activity of an energy producing and trading company in 2003 but found that allegations that its conduct in the short term power markets may not have been for legitimate commercial purposes were unsubstantiated. In France there have been no allegations of breaches of rules on proper market conduct. In Germany no formal investigations were carried out.

[249] Nord Pool Market Conduct Rules (in particular, section 4.1) and Disclosure Rules (in particular, section 2.1). Furthermore, Nord Pool Ethical Guidelines state that market participants shall never compete in an unfair manner.

[250] Article 3 of the Law of 10 February 2000 on the modernisation and development of the public service of electricity as modified by article 51 of Law 2005-781 of 13 July 2005 on the orientation of energy policy.

Conclusions

The need for greater transparency is widely recognised and has been identified as the key non-structural measure that could improve competition in EU electricity markets. Lack of transparency amounts to an entry barrier, undermines the level playing field between market participants and adversely affects the trust in the functioning of the wholesale markets.

In practice in most Member States the level of transparency remains low. There are also significant differences between Member States undermining the level playing field. More than 80% of all market participants are not satisfied with the current level of transparency arguing that not all indispensable, important and/or useful information is made public. More information should be published on technical availability of interconnectors and TSO networks, on generation, balancing and reserve power and load.

The EC financial services legislation, even when it applies to electricity wholesale markets, imposes only limited transparency obligations on these markets or their participants. The same applies to the sector-specific rules.

The transparency requirements under national rules or market conditions appear to be widely divergent, with for example only Nord Pool explicitly banning trading before the relevant information has been passed to the market. Furthermore, experience with enforcement of the national rules and the market conditions are even more divergent, with only Nord Pool having a broad experience enforcing its rules

There is therefore an urgent need to require all market participants to publish more information. The Commission will consider whether there is a need for Community legislation in this area (e.g. clarification or modification of existing legislation or new legislation). The Commission will also consider imposing transparency requirements as remedies in competition cases, given that improved transparency can help to limit the possibility to abuse market power.

II.5. Price issues

(542) Whilst the formation of electricity prices on wholesale markets has already been explained in some detail in this report, three issues relating to the overall price level of electricity deserve particular attention. First, it needs to be analysed which external factors might explain – wholly or in part – the price increases over the last years such as increases in fuel costs or the introduction of the CO2 emission trading scheme (ETS). Secondly, the effects of publicly set supply tariffs for competitive electricity wholesale markets need to be assessed. And thirdly, special support schemes – currently under consideration in certain Member States - to support large energy intensive users are presented and assessed.

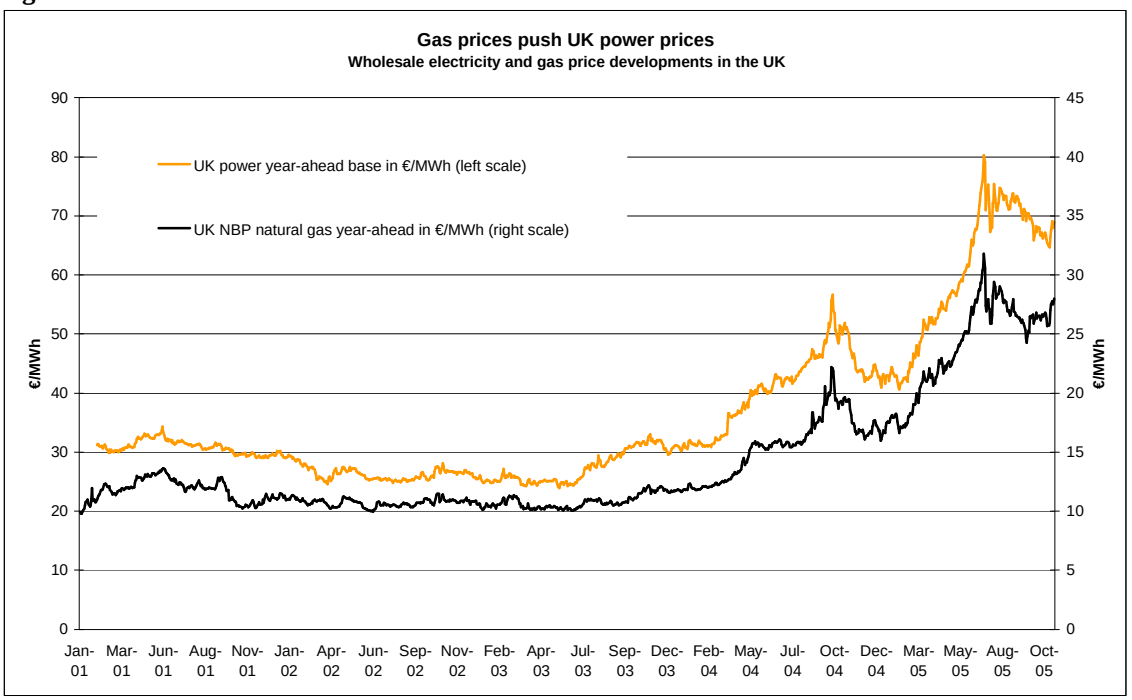
II.5.1. External factors possibly explaining price increases

II.5.1.1. Electricity prices and fuel price developments

(543) Coal and natural gas are commonly used primary energy sources to generate electricity throughout Europe. It can therefore be expected that their price development will affect electricity prices.

(544) Recent strong price increases of natural gas (themselves subject of the gas sector inquiry) had a significant impact on wholesale electricity prices especially in the UK, where natural gas constitutes the fuel that is predominantly used by generators on the margin. Figure 65 demonstrates this relationship showing the development of the UK forward natural gas and electricity prices. It is characterised by a high correlation between the price levels.

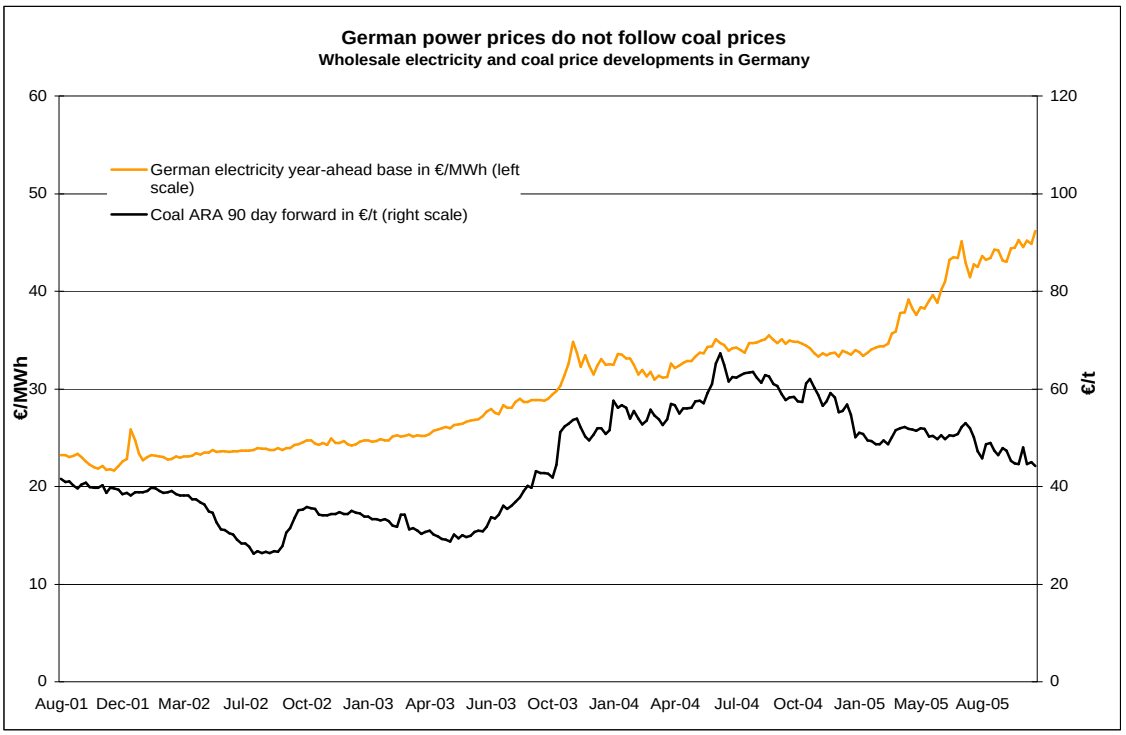
Figure 65



Source: information received within the scope of the Sector Inquiry from Argus Media, and platts

(545) In other parts of Europe coal (instead of gas) plays a major role in electricity generation. It is generally understood that (e.g. in Germany) coal is often used by generators operating on the margin. Thus coal price developments – all other factors being equal – should have a major impact on electricity prices. However, this was not the case in recent years. Whereas the relevant benchmark coal price has decreased (from 60 €/t in January 2005 to 44 €/t in December 2005), the year-ahead base load electricity price has risen significantly in Germany (from 34 €/MWh in January 2005 to 52 €/MWh in December 2005). Although electricity prices are also influenced by factors other then fuel prices (e.g. CO2 prices, trade with other countries) the reasons for this development will have to be studied in more detail. This is all the more important since the German market lacks the transparency that would allow market participants to identify the marginal generator or take an informed view on the development of supply fundamentals. Figure 66 shows the development of forward electricity and coal prices in Germany.

Figure 66



Source: information received within the scope of the sector inquiry from Argus Media, and platts

II.5.1.2. Electricity prices and CO2 price developments

(546) In addition to rising natural gas prices generators – as they explain in their answers – started to factor in the value of the CO2 allowances in their pricing decisions as an additional factor of production.

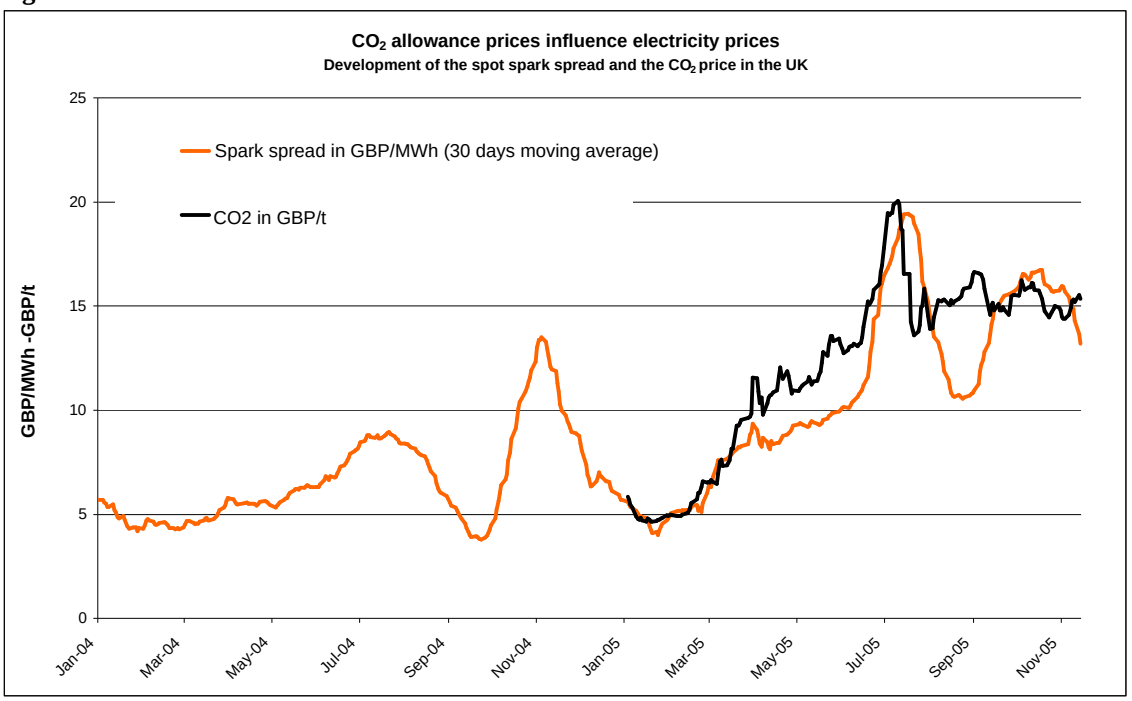
(547) There is no consensus yet among analysts to what extent prices for CO2 allowances are included in wholesale prices and/or whether in all Member States the same developments can be observed. Some argue however that the value of the allowances is at least partially priced in. A recent study by the Energy Research Centre of the Netherlands[251] concluded

[251] 'CO2 price dynamics: The implications of EU emissions trading for the price of electricity', Energy Research Centre of the Netherlands, September 2005

that in the Netherlands between 39% and 44% of the value is priced in at peak times and between 47% and 55% at off-peak times. In Germany between 42% and 46% of the value is priced in during off-peak times and between 69% and 73% during peak times. The European Commission Directorate-General for Environment closely follows the overall impact of the EU Emission Trading Scheme. It commissioned two corresponding and recently published studies.[252]

(548) The possible impact of CO2 trading on power prices – all other factors being equal – can be demonstrated using the concept of spark spreads. The spark spread is the difference between the price of one unit of electricity and the price of one unit of gas (adjusted for plant efficiency). It gives an idea about the revenue of generators burning gas and selling the generated electricity on the market. As long as gas constitutes the marginal fuel in a market one would expect a relatively stable development of the spark spread (apart from possible price distortions or short term supply/demand imbalances). A spark spread graph thus allows isolating the impact of the gas price on the electricity price.

Figure 67



Source: information received within the scope of the sector inquiry from Argus Media
Note: for the calculation of the spot spark spreads we used spot NBP prices and adjusted them for 50% plant efficiency. The spark spread is not corrected for the value of CO2.

(549) Figure 67 shows that the spot spark spread in the UK remained low and relatively stable (apart from a short period with tighter margin between demand and available capacity) during 2004 and started to rise from the beginning of 2005. This is also when the 1st phase of the EU Emission Trading Scheme began. It can be observed that the spark spread followed the pattern of the CO2 price development suggesting that generators – at

252 'Review of EU Emissions Trading Scheme: Survey Highlights', European Commission Directorate-General for Environment, McKinsey & Company, Ecofys, November 2005
'Interactions of the EU ETS with Green And White Certificate Schemes', European Commission Directorate-General Environment, NERA Economic Consulting, 17 November 2005

least to some extent - include the value the CO2 allowances into their pricing decisions.[253]

(550) CO2 allowance prices rose sharply during the first half of 2005 tracking the development of rising gas prices relative to coal prices. Because of high gas prices generators preferred to burn coal instead of gas to produce electricity. Since power plants using coal emit approximately twice as much CO2 as those burning gas as primary fuel, increased coal usage raised the demand for additional CO2 allowances. This in turn resulted in rising CO2 prices as can be seen in Figure 67.

(551) The practice of including the value of CO2 allowances in the cost calculations is seen - by certain industrial customers - as evidence for generators' market power (predominantly in Germany) and non-functioning of electricity markets. The critics underline that companies subject to global competition are not able to pass on costs associated with CO2 allowances to their customers (e.g. steel or aluminium producers, whilst electricity producers can do so). Critics also mention that the vast majority of the allowances were given for free to generators (generally between 95% and 100% of their demand). Customers claim further that generators would not only benefit from higher electricity prices for their marginal plant but for their entire production portfolio resulting in 'windfall profits'. Furthermore they are concerned that the current allocation scheme favours incumbents over new entrants into generation. However it needs to be mentioned in this context that the allocation plans of all 25 Member States as approved by the Commission for the period 2005-2007 contain new entrant reserves. This implies that new power plants will be given free allowances in accordance with the rules governing these reserves.

(552) However, in the view of electricity generators and traders, CO2 allowances are like any other variable factor of production. As such, CO2 allowance prices have to be included in the short run marginal cost calculation of the generating units. In this context – generators argue - it would not matter whether CO2 allowances were allocated for free or had to be bought on the market. It is claimed that the market value of the allowance is what ultimately matters (similarly to a house that was inherited but would be sold on the property market for market prices). If this value would not be taken into consideration the generator on the margin would see revenue that it could realise if it decided not to generate but sell the CO2 allowances and buy the electricity instead (opportunity cost principle). In any event pricing in costs for CO2 allowances would be in line with the objectives of the CO2 ETS.

(553) The Commission will continue to monitor the effects of the EU ETS (including the effect of the ETS on electricity prices), which is a major element in its strategy to achieve the Kyoto obligations

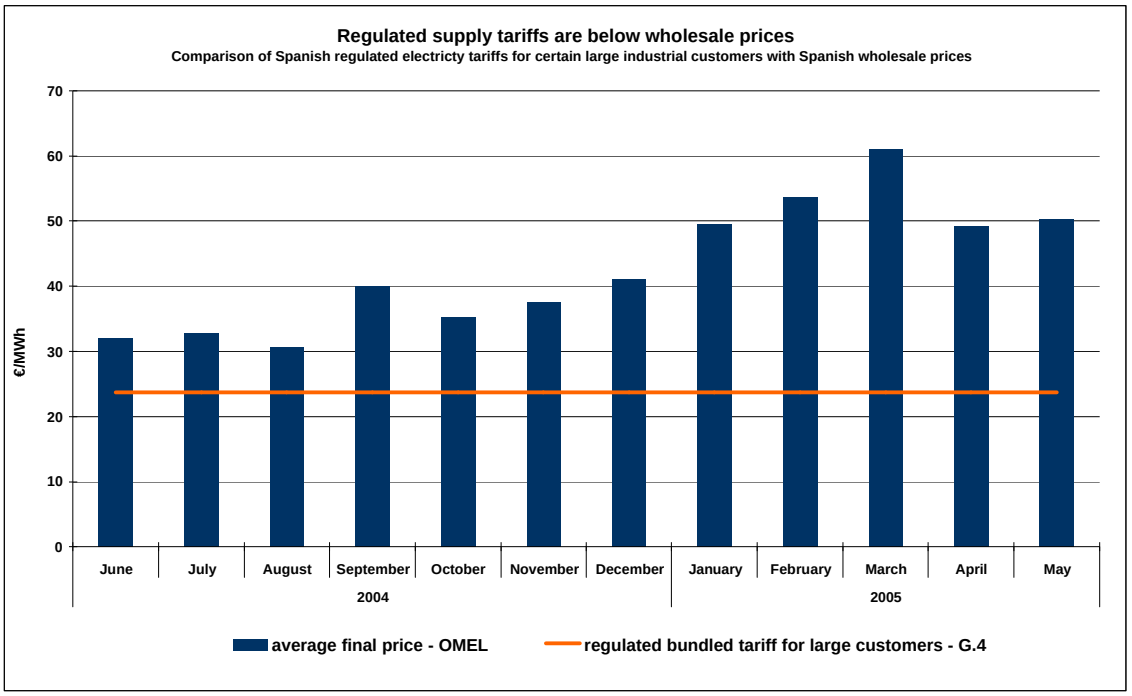
[253] Similar trends can be observed when analysing forward spark spreads.

II.5.2. Regulated supply tariffs

(554) In a number of markets that have been examined, the liberalised supply market with its freely negotiable energy prices between suppliers and customers coexists with a system of regulated final customer tariffs[254] (e.g. Portugal, France, Italy, Spain, Hungary, Poland). Parallel regimes are no threat to a liberalised supply market and its participants as long as regulated energy prices are comfortably above wholesale market price levels. This differential allows for (new) suppliers without any local generation to source on the wholesale market and make attractive supply offers compared to the regulated energy tariff.

(555) However, Member States could be tempted – especially in periods of rising wholesale prices – to set the supply tariffs below the corresponding wholesale benchmark to ensure lower price levels for customers. An adverse effect of such tariffs is however that new suppliers with no access to own generation are squeezed out from the market. Electricity suppliers, in particular in Spain and France, complained about the level of regulated tariffs being too low.

Figure 68



Source: OMEL, CNE (Spanish Regulator)
Note: The G.4 bundled tariff depends on a capacity and consumption element and also includes network usage

254 See also Second Electricity Directive, Art.3, Public service obligations and customers protection. Another issue is the exclusivity granted to incumbents to supply within regulated markets.

II.5.3. Special support schemes for energy intensive users

(556) In the light of increasing electricity prices a number of Member States are considering special support schemes for large energy intensive users. Whilst a number of different concepts seem to exist, one of the most advanced relates to the formation of purchasing consortia under criteria set by national legislation. The consortia would enter into long term supply contracts with electricity producers guaranteeing lower electricity prices for the members of the consortia. These purchasing consortia may raise antitrust and possibly also state aids concerns.

(557) From an antitrust point of view the main questions are: a) How are the purchasing consortia formed? The underlying issue is that the possible exclusion of certain companies from consortia can put them at a competitive disadvantage compared to those being part of the consortium benefiting from the lower electricity prices. b) Do the long term contracts have foreclosure effects? This may be the case if the companies which acquire electricity would account for a significant proportion of the overall electricity demand in the market concerned. And c) Are the participants in the consortia free to market the electricity? The electricity supplier might have an interest in preventing the buyers from marketing unused electricity at low prices. However, such a contractual restriction may be problematic use restriction.

(558) The major concerns as regards aid are that any such aid exceeding the de-minimise thresholds would be viewed as operating aid which normally is not allowed in the EU. It would in any case not be possible for the Commission to authorise such aid based on any existing State aid guideline. It can also be questioned whether there would be a need to provide such aid since the mere effect of the establishment of a consortium is supposed to trigger a reduction in price.

(559) Further analysis will be required as regards these special support schemes.

Conclusion

In certain Member States the recent increases of electricity prices can be explained by the rise of gas prices used in marginal plants. However coal prices have remained relatively stable thus not explaining any price increases. Analysts cannot yet agree to which extent the value of CO2 allowances is priced into electricity prices.

Industrial users claim that electricity producers should not be entitled to factor in the value of allowances, as they were largely distributed for free. Generators claim that the value of CO2 allowances are opportunity costs, which can be factored in legitimately. The Commission will closely monitor the effects of the ETS.

Public tariffs for electricity supply can have an adverse effect on the development of competitive markets. Support schemes for large energy intensive users – currently considered in a number of Member States – need to be compatible with antitrust and state aid rules.

D CONCLUSIONS

(560) The overall objective of the Inquiry is to address the barriers currently impeding the development of a fully functioning open and competitive EU wide energy market as a basis for competitive prices for the final consumer, more efficient allocation and use of resources and supply, more openness for renewable energies and an economically sustainable basis for security of supply. The wider context has been set out in the Commission's Communication to the 2006 Spring Council concerning the renewed Lisbon strategy that puts the formulation of an efficient and integrated energy policy at the heart of the Commission's priorities[237]. This context will be further developed in the announced Green Paper on energy policy to be submitted by the Commission in early March.

(561) The launch of the Inquiry into the functioning of the European energy markets in June 2005 was prompted by dramatic rises in gas and electricity wholesale prices and persistent complaints about barriers to entry and limited consumer choice. The energy sector inquiry is a competition investigation based on Art. 17 of Regulation 1/2003 which aims at assessing the competition conditions on European energy markets and establishing whether current indications of energy market malfunction result from breaches of competition law.

(562) At this stage of preliminary findings and on the basis of the further assessment of the data received during the Inquiry, the overall conclusion is that the main problems areas identified in the Issues Paper[238] have been confirmed. Main findings at this stage can be summarised as follows.

(563) Market concentration

- *Gas:*

Access to gas for new entrants is essential for the future development of European gas competition. There are three main sources from which gas may be sourced: imports, domestic production and wholesale trading. Gas incumbents remain dominant in their national markets by largely controlling gas imports and/or gas production. Control of imported gas is mainly exercised through long term gas purchase contracts with upstream producers. Although incumbents trade only a small proportion of their gas on Continental hubs they nevertheless dominate trading on most hubs.

There has been little new entry into the European gas markets. The overall picture for new entrants is one of dependence on incumbents for services throughout the supply chain. This includes access to gas, networks and storage. When combined with the lack of transparency, ineffective wholesale markets and in the absence of effective regulation this dependence affirms the dominant position of incumbents and is seriously impeding the development of competition.

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237 In the Communication the Commission proposes the promotion of more competition on the electricity and gas markets as a major goal (Action 4: "Moving towards an efficient and integrated EU energy policy*")"taking account of the Commission's sector competition enquiry"*.

238 Energy Sector Inquiry – Issues Paper of 15 November 2005, available at DGCOMP's website, Sector Inquiries.

Electricity:

Customers have little trust in the functioning of wholesale markets. They suspect market manipulation on the spot and forward markets by large generators to be the main reason for recent price increases. However there are a number of other factors that might explain price increases that require further investigation.

Most wholesale markets have remained national in scope. The level of concentration in generation has remained high in most Member States giving generators scope for market power. The level of concentration in trading markets is less striking than in generation, particularly when analysing shares of operators on yearly forward products. The level of concentration on spot markets reflects more closely the level of concentration in generation, although at a lower level. When analysing who determines the clearing price at certain power exchanges it appears that there is scope to influence prices for operators in Italy, Spain and Denmark. The situation on the French, Dutch and German exchanges will be further assessed.

When analysing whether there is scope to withdraw physical capacity, it appears that load factors have increased over time in Germany suggesting higher efficiency levels and a tighter supply/demand balance. Significant generation capacity – most of it with low marginal costs – was retired in Germany despite slowly increasing demand. Also, certain plants with rather low marginal costs did not operate fully at all times. Further investigation is foreseen for the subsequent phase of the sector inquiry to disentangle the different reasons for price increases.

(564) Vertical foreclosure

- *Gas:*

Vertical integration of operators active at different levels of the supply chain and long-term supply agreements seem to foreclose the availability of crucial inputs for actual or potential competition:

Access to gas

New entrants can procure gas either directly from producers, or on national wholesale markets. Incumbents have long-term import contracts in place with producers, which cover the production of almost all existing gas fields from which gas can be transported to Europe by pipeline. New entrants are therefore largely foreclosed from procuring gas directly from the producers. At the same time, most national wholesale markets are not liquid enough to provide confidence about gas availability or that hub prices reflect the underlying supply/demand dynamic. This lack of liquidity is aggravated by flexibility clauses in the incumbents' long-term supply contracts which avoid situations of excess or shortage of gas, thereby reducing the incumbents' need to trade gas at national wholesale markets.

Access to storage

Access to storage is seriously foreclosed by long-term reservations. In some cases booked storage is not being fully used. Moreover, separation of suppliers from affiliated storage operators is unclear, leading to concerns about non-discrimination.

Insufficient unbundling of networks

Legal and organisational unbundling as foreseen by the Second Gas Directive is not yet fully implemented and incumbent suppliers still have access to network information through representation on the Supervisory or Administrative Board of vertically integrated companies. Suppliers and networks often share names/logos, buildings and IT systems. A number of allegations of discrimination by network operators in favour of affiliates have been received.

- *Electricity:*

Vertical integration of generation and retail reduces the incentives to trade on wholesale markets. This might lead to a drying up of wholesale markets. Illiquid wholesale markets are a barrier to entry as they are characterised by higher price volatility. Volatile wholesale markets might oblige new entrants to as a enter vertically integrated generator and supplier, which is more difficult.

The degree of vertical integration between generation and retail differs significantly between Member States. In most Member States there are few companies with long positions leading to high “levels of concentration”. VPPs (auction of electricity) assist in some Member States (e.g. France) to improve the level of concentration. Long term power purchase agreements (PPAs) have similar effects to vertical integration.

According to respondents', vertical integration of supply and network (transmission and distribution alike) reduces the economic incentives for the network operator to grant third parties access. In the views of many respondents the existing rules on legal unbundling do not ensure that vertically integrated companies do not engage in practices favoring their supply affiliates to the detriment of their competitors.

With respect to transmission networks, a number of respondents complained about significant costs to connect new power plants to the network. No means exists to verify whether claims of congestion or costs for network reinforcements are valid. With respect to the distribution networks, respondents reported amongst other things inappropriate switching procedures, a lack of Chinese walls between network and supply branches and discriminatory access tariffs.

(565) Market integration

- *Gas:*

Cross-border sales do not currently exert any significant competitive pressure in EU wholesale markets. The concentration of the historical incumbents in their domestic markets is mirrored by their lack of sales in other markets. Swaps are not a marginal phenomenon and can substitute physical transport of gas. However, they are largely tools used by incumbents. New entrants are unable to secure *primary* transit capacity on key transit routes due to the predominance of long-term contracts signed between incumbent TSOs and, typically, their supply affiliates. This situation is expected to persist for the term of the pre-liberalisation legacy contracts (typically fifteen to twenty years of duration) but also potentially beyond this time due to the existence of provisions allowing these contracts to be extended.

On a number of the most congested transit pipelines the volume of requests for additional capacity (much of it from new entrants) is material in comparison to the existing technical capacity of these pipelines, indicating a significant level of unsatisfied demand for transit capacity.

Even in instances where the capacity of particular transit lines has been increased, the resulting new capacity has, for the most part, ended up in the hands of the companies that already controlled the pre-existing primary capacity. The current process for financing new investment risks cementing market shares in destination markets and forming a barrier to smaller players participating in the market.

Moreover, access to *secondary* transit capacity, which should be in theory open to new entrants, has in reality not been obtained by them, with the majority being secured by incumbent suppliers from other countries or large gas producers. Due to the lack of effective congestion management mechanisms on the majority of transit pipelines, it is seldom possible for new entrants to secure even smaller volumes of short-term, interruptible capacity.

- *Electricity:*

Imports do not yet adequately play their role to counter market concentration in national markets and exert competitive pressure on incumbent operators. Hence consumers may pay more for their electricity than strictly necessary. Important reasons for inadequate market integration include:

- Insufficient levels of cross border capacity,
- Inefficient congestion management methods (including explicit auctions),
- Important differences in rules that manage the electricity markets administratively within and between control areas,
- Long term cross border capacity reservations, partially given under discriminatory conditions, and
- Lack of adequate incentives to invest in additional capacity.

(566) Transparency

- *Gas:*

Network users request more transparency on access to networks and transit capacity, as well as on storage. Users would like to see more detailed information than is currently provided for by the minimum requirements set by the Gas Directive and the Guidelines annexed to it. Notably, network users question the "three or more" rule and favour the enhancement of secondary trading by the publication of unused capacity. A number of new entrants would welcome the creation of a single transparent and integrated web platform providing information on available capacity for all transit pipelines. As far as storage is concerned, users underline the need for detailed information.

- *Electricity:*

The need for greater transparency is widely recognised and has been identified as the key non-structural measure that could improve competition in EU electricity markets. Lack of transparency amounts to an entry barrier, undermines the level playing field between market participants and adversely affects the trust in the functioning of the wholesale markets.

In practice in most Member States the level of transparency remains low. There are also significant differences between Member States undermining the level playing field. More than 80% of all market participants are not satisfied with the current level of transparency arguing that not all indispensable, important and/or useful information is made public. More information should be published on technical availability of interconnectors and TSO networks, on generation, balancing and reserve power and load.

The EC financial services legislation, even when it applies to electricity wholesale markets, imposes only limited transparency obligations on these markets or their participants. The same applies to the sector-specific rules.

The transparency requirements under national rules or market conditions appear to be widely divergent, with for example only Nord Pool explicitly banning trading before the relevant information has been passed to the market. Furthermore, experience with enforcement of the national rules and the market conditions are even more divergent, with only Nord Pool having a broad experience enforcing its rules.

There is therefore an urgent need to require all market participants to publish more information. The Commission will consider whether there is a need for Community legislation in this area (e.g. clarification or modification of existing legislation or new legislation). The Commission will also consider imposing transparency requirements as remedies in competition cases, given that improved transparency can help to limit the possibility to abuse market power.

(567) Price formation

- *Gas:*

Prices in most European long-term supply contracts are currently linked to heavy and light fuel oil.

Companies from the Netherlands, Norway and Russia, three of the major gas producers in Europe, all sell long-term gas with a price which is principally linked to heavy and light fuel oil. Companies from the UK and other intra-EU producing countries have a more mixed indexation in their pricing formulae, including an element of hub gas prices.

Whilst the price paid for gas under long-term contracts by companies from Western and Eastern Europe are principally indexed to oil derivatives, in the UK hub gas prices are the most important variable in determining the prices paid by companies purchasing gas under long-term supply contracts.

The overall price level of gas is similar for all gas producing regions. The interquartile range of long-term gas contract prices seems to be dependent on the amount of hub gas price indexation present in the contract.

In almost 90% of cases where two or more producers are selling from the same field to the same wholesaler, the price indexation in the long-term contracts is the same. Furthermore, in almost two thirds of these cases, the same actual price is being paid by the wholesaler to the producers.

Long term gas contracts exhibit a constant price throughout the period January 2003 to December 2004, whereas hub prices are much more volatile. In particular, hub prices change significantly from the summer to the winter, due to increased demand for energy. These price signals are not incorporated into the pricing mechanism of most long-term gas supply contracts.

Long-term contracts with prices indexed mainly to gas also display seasonality, but on a volume weighted basis their price level tends to be in line with that of long-term contracts indexed to oil, which do not display any seasonality or response to demand signals. This is because contracts indexed to hub gas prices are more expensive during the peak winter months when most gas is consumed.

A number of Member States have some form of regulated prices which may have negative effects on competition, where these prices are set too low.

- *Electricity:*

In certain Member States the recent increases of electricity prices can be explained by the rise of gas prices used in marginal plants. However coal prices have remained relatively stable thus not explaining any price increases. Analysts cannot yet agree to which extent the value of CO2 allowances is priced into electricity prices.

Industrial users claim that electricity producers should not be entitled to factor in the value of allowances, as they were largely distributed for free. Generators claim that the value of CO2 allowances are opportunity costs, which can be factored in legitimately. The Commission will closely monitor the effects of the ETS.

Public tariffs for electricity supply can have an adverse effect on the development of competitive markets. Support schemes for large energy intensive users – currently considered in a number of Member States – need to be compatible with antitrust and state aid rules.

E WAY FORWARD

In the Issues Paper the Commission services had announced that it would discuss and propose any necessary *structural, regulatory and competition law based remedies*, once the assessment of the findings of the Inquiry and the parallel reviews of implementation of the Liberalisation Directives had been concluded. It is therefore too early to draw conclusions at this stage and comments are solicited during the forthcoming two months consultation period following the publication of the report and the wider debate in the context of the forthcoming Green Paper, which will allow the Commission to reach conclusions at the end 2006. Nevertheless, from the point of view of the Commission services a number of preliminary remarks can be made now.

Competition law

The Commission is pursuing infringements of Community competition law in the sector wherever the Community interest so requires, in accordance with the regulations in place and in close cooperation with National Competition Authorities. Even before the completion of the Inquiry, the current findings will help to carry forward procedures with full knowledge of the market environment and to orient priorities towards the most serious problem areas.

(1) *Market Concentration* has been identified as the major problem and this makes the Community's action under the merger regulation essential. While each merger case is assessed according to its specific characteristics, the Inquiry helps to identify the most relevant criteria and the most efficient remedies in the given market environment.

(2) *Vertical foreclosure: Tying of downstream markets*. The Inquiry has confirmed that foreclosure of the downstream market by long-term contracts is an immediate priority for review of case situations under competition law. During the forthcoming phase of the Inquiry, the data collected will be further screened and any foreclosure effect closely analysed.

(3) *Market integration: access to capacity on pipelines, gas storage and on interconnectors* has been found to be a major stumbling block towards more market integration and should be the other immediate priority for review in terms of anti-competitive conduct.

The findings indicate that the use of market partitioning clauses continues in a number of Member States. This will need further attention during the final phase of the Inquiry.

Besides these priority actions focusing on market concentration, downstream market foreclosure, and market integration, other case situations of anti-competitive and exclusionary conduct deserve immediate attention, such as inhibiting customers from switching suppliers.

The issuance of guidance on the application of Articles 81 and 82 EC to various practices in the sector may be envisaged. The Commission welcomes comments on the need for such guidance during the consultation.

Regulatory

The Commission has undertaken to review on a Member State by Member State basis the implementation of the gas and electricity liberalisation directives during 2006, and to submit proposals by the end of the year[242] .

While more time will, therefore, be needed to reach conclusions in this field, from a competition perspective a number of issues already seem to emerge from the preliminary findings .

(1) A main finding is that *transparency* is insufficient in the sector. There seems to be broad consensus that this issue should be addressed by strengthening transparency obligations, be it under regulation or under competition law.

(2) There are substantial indications that the remaining *"grandfathering rights"*[243] seriously impede effective entry of competitors and therefore undermine the pro-competitive operation of the market.

(3) Whilst progress has been made in fixing common rules regarding the interconnectors between national grids, much more needs to be done. While there are a number of schemes between national regulators in place or being set up concerning coordination in this area, the findings suggest that purely voluntary cooperation schemes between regulators are unlikely to provide the investment certainty and regulatory protection that is needed to develop international pipelines and interconnectors in a stable environment and keep them open.

There are a number of other regulatory issues that have been raised by both market participants and regulators and which will have to be further considered during the ongoing reviews of the implementation of regulation in the sector. It seems that in a number of Member States, the powers of national regulators should be increased in a number of areas. For example, one area appears to be the surveillance of the conditions and prices for Third Party Access for competitors in order to make pro-competitive markets work and allow consumers to benefit.

Issues under review

There are a number of issues on which it would be premature to take position at the current stage of the assessment but on which comments are solicited:

– price setting practices on electricity wholesale markets including power exchanges

– the competitive assessment of the gas / oil price linkage in many contracts

– the exemption from Third Party Access provisions in the gas directive (in cases of new investment in pipelines, storage and LNG terminals)

242 Commission Report on Progress in Creating the Internal Gas and Electricity Market, 15 November 2005.

243 Capacity rights stemming from pre-liberalisation monopoly contracts.

– a possible more generalised use of gas and electricity release programmes under regulation, in order to reduce the effect of concentration in the upstream supply level and inject liquidity into the market, as well as other measures reducing the effects of concentration,

– further measures to reduce upstream supply concentration, and

– the impact of the Emission Trading System (ETS) on prices in the electricity market. The Emission Trading System is central to a cost effective attainment of the Kyoto green house gas reduction goals and therefore must be seen in a wider policy context. The Commission has committed to undertake a review of the functioning of the scheme before the end of the year.

Structural

While the measures and issues set out above and submitted for consultation would address a number of the key problems found at this stage of the Inquiry, the findings of the inquiry suggest more and more strongly that a real breakthrough towards effective competition in the gas and electricity markets by 1st July 2007 will not be possible unless the root causes of the market malfunctioning are addressed. The market structure suffers from a systemic conflicts of interest resulting from the vertical integration, in many cases, of the supply, transport and distribution level.

This situation dates from the pre-liberalisation period and prevents the advantages of an efficient competitive market reaching the final consumer in a meaningful manner. It makes the Community's energy system less receptive to the introduction of new forms of energy such as renewables due to the stake holders' interest at all three levels of the value chain; and it prevents an effective diversification of supply, which is an indispensable element towards more security of supply.

The provisions of the second electricity and gas Directives on unbundling need to be fully implemented, not just in their letter but also in their spirit. If real progress in this respect does not develop and a true level playing field result, further measures such as full structural unbundling (i.e. separation on the supply and retail business from monopoly infrastructures) should be considered[244].

Comments on this issue are also welcome during the consultation period.

[244] Member States are addressing the issue of unbundling under the existing Directives and national regulation along different routes. Certain Member States have introduced full “ownership unbundling”.

F PUBLIC CONSULTATION

This Inquiry must be seen in the context of the current wider overhaul of the Community's energy policy and the positions that will be set forth in the Green Paper on energy policy. It is intended to proceed to the final phase of assessment of the Inquiry after a two month consultation period that will start with the public presentation of the Preliminary Report on 16 February 2006. Comments are solicited before 1 May 2006 and should be sent to comp-energy-sector-inquiry@cec.eu.int.