

COMPETITION IN EU ELECTRICITY MARKETS
Submission by Barclays Capital to DG Energy and Transport
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1. Introduction and Summary

The single market vision is of free and vibrant competition to produce and source electricity and gas across the EU via deep, liquid and transparent wholesale markets. Aside from further work on gas storage, the passage of the gas transmission regulation should largely complete a comprehensive EU legislative framework to underwrite EU energy liberalisation. In theory, at least, all customers will have a choice of supplier from July 2007 and unbundling and regulated third-party access should ensure that all market participants enjoy non-discriminatory access to the delivery networks - within and between – Member States on economic terms. Events on the ground, however, are struggling to catch up with this legislative vision. Despite extensive and valuable discussions on market reform, there have been few genuinely competitive developments of the ground since the Commission's last Annual Report.

Most EU markets remain dominated by a small number of vertically integrated incumbents and consolidation has further reduced the number of independent competitors across the EU. Competition across the borders between member states continues to be constrained by long-term contracts and arcane capacity allocation rules. Finally, outside of the UK and Nordic markets, retail competition remains more of a theoretical possibility and in some areas seems an ever more remote possibility following recent wholesale price rises. The current investigations by DG Competition and DG Transport and Energy represent a valuable opportunity to address this gap between the legislative framework and the development of effective competition and to identify further measures to stimulate the internal energy market. In the meantime, national regulators and the Commission could improve significantly the levels of cross-border competition by ensuring that the requirements of the electricity cross-border regulation are fully implemented and by improving access to essential market information across EU energy markets. We address these two issues in sections 2 and 3 respectively. As we discuss in section 4, cross-border competition and competition within national markets could also be significantly enhanced by extending the trading arrangements and the opportunity for competition within day and by removing many of the logistical constraints on effective competition between markets.

This is a crucial and challenging time for the internal energy market. Not only are regulators tasked with implementing the liberalisation agenda, but regulators and market participants are currently being asked to fulfil an increasingly diverse set of environmental objectives, to underwrite security of supply and to protect customers in the light of rising energy costs. The massive challenge now is to deliver on these diverse objectives without discarding the benefits of liberalisation before they have been fully realised. To this end, as we discuss in section 5, it is crucial that where regulators do take steps to reduce the impact of market concentration (eg, through virtual power plant auctions) the potential for these programmes to enhance competition is maximised and that any regulatory measures to protect customers, the

environment or to underwrite security of supply are supplementary to the market and do not undermine competition.

Although, in this paper we have focused on the developments in the EU electricity sector, all of the analysis and recommendations apply equally to the gas sector particularly in respect of the need to be able to access cross-border capacity and the requirements to secure further information transparency.

2. Ensuring Effective Cross-Border Competition

Ensuring effective cross-border competition is one of the main instruments to enhance competition in the EU wholesale energy markets which, in turn, will facilitate potential new entry into the generation and supply markets. The electricity cross-border regulation is a hugely powerful tool to foster cross-border competition in the EU. The Regulation's requirements on system operators to release the maximum amount of cross-border capacity in a non-discriminatory, market-based fashion should have led to a brave new world of open, coordinated capacity auctions at all borders from July 2004. Instead there is a widespread failure to implement the Regulation and the continuance of arcane, discriminatory and inefficient allocation methods at many borders. As we describe in section 2.1 below, the result is a continuing inability for market participants to access interconnection capacity, to compete effectively across borders and the underutilisation of already scarce capacity.

While already powerful when taken in its entirety, the Cross-Border Regulation leaves significant scope for interpretation from regulators and system operators and would benefit from greater clarity and compulsion in some areas. Specifically, we believe that the focus should shift away from short-term congestion management towards the provision of long-term cross-border transmission services by TSOs. As we outline in section 2.2, effective cross-border competition – and hence the success of the internal electricity market – depends crucially on the ability of market participants to be able to lock in the price of transmission between national markets. Since the market alone will not provide market participants with the ability to lock-in transmission prices (for the reasons outlined in section 2.3) regulators should require system operators to sell forward transmission rights which allow market participants to lock in transmission prices (as discussed in section 2.4) and to facilitate a secondary market in these rights (section 2.5). In sections, 2.6 and 2.7, we explain the importance of ensuring that these forward cross-border transmission rights are both long-term and financially firm.

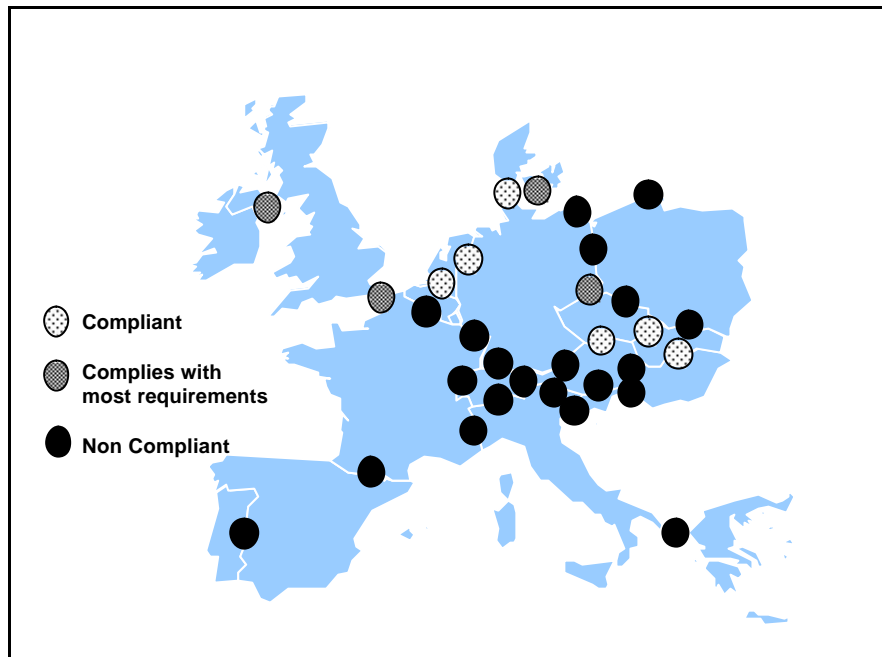
Despite the compelling competitive arguments in favour of providing long-term transmission capacity, TSOs have nevertheless been reluctant to adopt them on the grounds that transmission capacity is inherently unpredictable and an unwillingness to take the associated risks. In section 2.8, we respond to these arguments and explain why the risks are likely to be relatively minor and manageable and in section 2.9 we outline some suggestions for improving the regulatory framework to require and to give incentives to regulators and systems operators to provide efficient cross-border transmission services in a way that will enhance cross-border competition.

2.1 The Continuing Failure to Implement the Cross-Border Regulation

We continue to be hugely frustrated by the failure of most Member States to implement the provisions of the Regulation for the past year. Instead of being a starting point for market-based allocations (eg, simple auctions of existing capacity) with a subsequent dialogue on incremental developments and improvements, July 2004 seems to have been merely the starting point for prolonged discussions on what does or does not qualify as a market-based allocation. The result is that we have lots of discussion about various projects aimed at compliance (Belpex, France-Spain, France-Germany etc), but with very little by way of

concrete deadlines or concrete details of crucial elements (eg, how much capacity will be available via Belpex). Despite the merits of some of these proposals, the ongoing discussions on the projects, associated mini-fora and the revised draft guidelines have deflected attention from the bald fact that nothing positive has actually happened in practice since July 2004. Figure 1 illustrates the current state of compliance with the cross-border regulation across the EU.

Figure 1: Compliance with Cross-Border Regulation



In some instances we have actually seen the situation get worse , for example:

- The daily (and subsequent quarterly) auctions introduced for the German-French border breach the Regulation’s requirements in several important respects (illustrated in Case Study 1 in the text box below). The result has been to reduce cross-border flows between Germany and France, to undermine further the associated liquidity in the French market and to convert a previously unconstrained border into a significant source of revenue for the two associated German system operators (RWE and EnBW).
- On 30 June 2005, the Spanish Government changed the Spanish market rules to give the long-term contract between EDF and Red Electrica priority scheduling rights into the Spanish market, even when cheaper power is available to the Spanish market. This raises two curious alternatives:
 - That the long-term contract includes provisions which guarantee priority access to the interconnector but that these rights were not codified into the market rules (which, while possible, seems an unlikely oversight); or
 - That the long-term contract did not contain any provisions relating to priority access to the interconnection and hence these rights have been granted ex post in breach of the Regulation’s requirements that access should be non-discriminatory and that “existing long-term contracts shall have no pre-emption rights when they come up for

renewal” (which, by extension, we assume means that they also have no pre-emption rights if no explicit, existing right to the capacity exists).

On the ground, we continue to have to deal with inefficient and discriminatory systems for capacity allocation. In some cases (eg, Belgium-France), these systems effectively preclude participation completely for market participants not featuring on the priority lists. At other borders (eg, France-Spain) our ability to participate economically in moving power between the markets is frustrated by inconsistencies between the rules on either side of the border, when an easy solution – eg, to adopt the Spanish day-ahead allocation – is available at no cost and without delay (Case Study 2 in the text box below illustrates).

As the German case study illustrates, capacity auctions are also only one element of providing efficient cross-border access. There must also be transparent, coordinated and economic procedures for managing congestion and calculating available capacity if the potential for cross-border competition is to be maximised. In this regard, it is an ongoing source of great concern that even well-developed proposals for coordinated congestion management (eg, Belpex) are currently silent on exactly how the cross-border capacity will be calculated and on how this will be released to market participants in the form of long-term rights to move power between markets.

From this point forward therefore, the first step is clearly to enforce rigorously and immediately the terms of the Regulation by ensuring that capacity is freely auctioned at all borders prior to the further development and resolution of more sophisticated solutions to the determination of cross-border capacities and congestion management (eg, via market coupling).

Case Study 1

Capacity Determination at the German-French Border

On 5 April 2005, RWE Transportnetz (RWE-T) and EnBW Transportnetz (ENBW-T) implemented a day-ahead auction for the capacity on the interconnection between France and Germany. Although the auction qualifies as a market-based allocation, the implementation is largely inconsistent with the wider requirements of efficient cross-border competition and the Cross-border Regulation in several respects:

1. Despite the requirement that “national Regulators shall ensure that no congestion management procedure with significant effects on power flows in other networks is devised unilaterally”, the auction was nevertheless devised unilaterally.
2. Market participants were only informed of the final auction rules auction on 22 March 2005 and there was no opportunity for market participants, neighbouring system operators or regulators to consider the proposed changes. (Indeed the German regulator did not exist at the time). Consultation would have been particularly valuable given that the border has been largely unconstrained historically.
3. Rather than focusing on the German-French border, the loop flows via Switzerland and Austria (on one side) and Belgium and the Netherlands (on the other), require a broad, coordinated view to be taken of the German-French capacity and the purported congestion at this border.
4. The interconnection is rarely constrained (by our estimates less than 0.5 per cent over the past year), which raises the question as to whether an auction is actually necessary.
5. The “constraint” at the French border appears to relate to excessive flows from Germany to the Netherlands, which in turn, RWE have indicated results from excess wind generation in Northern Germany. This would breach the requirement that “TSOs shall avoid limiting interconnection capacity in order to solve congestion inside their own control area”. Rather than constraining German-French flows, a more appropriate solution to this problem may therefore have been to adopt North and South trading zones in Germany.
6. The auction is for entry/exit rights to/from Germany only which leads to potential inconsistencies between the priority list access to capacity for entry and exit to and from France. Although RWE and EnBW have indicated that they will work with RTE to develop a coordinated mechanism, to date there has been no further information or consultation with system users on the content of these discussions.
7. There is no netting of the French-German flows in opposite directions contrary to the Regulations requirements. This is particularly onerous given the existence of a long-term contract which continues to flow from France to Germany even when this is uneconomic (ie, when French prices are higher than those in Germany) and hence artificially reduces the available capacity.
8. The capacity is not firm and can be curtailed as a result of routine load flow changes or power plant outages. Curtailing border capacity can therefore become a low-cost alternative to the system operators procuring sufficient operating reserves within Germany.

Case Study 2

Inconsistent Allocations at the French-Spanish Border

The French-Spanish interconnector has two separate mechanisms for allocating capacity:

- Capacity to enter/exit Spain is allocated according to successful offers into OMEL
- Capacity to exit/enter France is initially allocated on a first-come-first-served basis with subsequent pro rata reallocations of unused capacity

Mismatches between these two allocation systems often leave capacity unused to the detriment of competition and Spanish consumers. (Moreover, the French system in itself continues to breach the Regulation's requirements for non-discriminatory, market-based access.)

In theory, French market participants should only nominate capacity or request further capacity in line with their projected usage according to the economically scheduled flows on the Spanish side. However, in practice:

- Holders of first-come, first-served priority list capacity in France can nominate day-ahead exports from France without the corresponding sale in OMEL in the hope of displacing other market participants who, despite having successful day-ahead schedules into Spain, are unable to acquire the corresponding French export rights;
- Market participants can apply for capacity in the daily (pro rata) reallocation in France in the hope of displacing those who have successfully sold power into Spain (and who are forced to reduce their energy sales to OMEL in the absence of French export capacity) in order to free up capacity to deliver themselves into Spain.

The allocation of capacity therefore becomes a speculative volume game, rather than one based on the underlying economics of delivering power from France to Spain (and vice versa). The result is that those that have secured the economic right to import into Spain may nevertheless be curtailed because they were unable to secure French exit rights. Moreover, those participants that have secured the French exit rights often fail to use the capacity that they have been awarded via the reallocation.

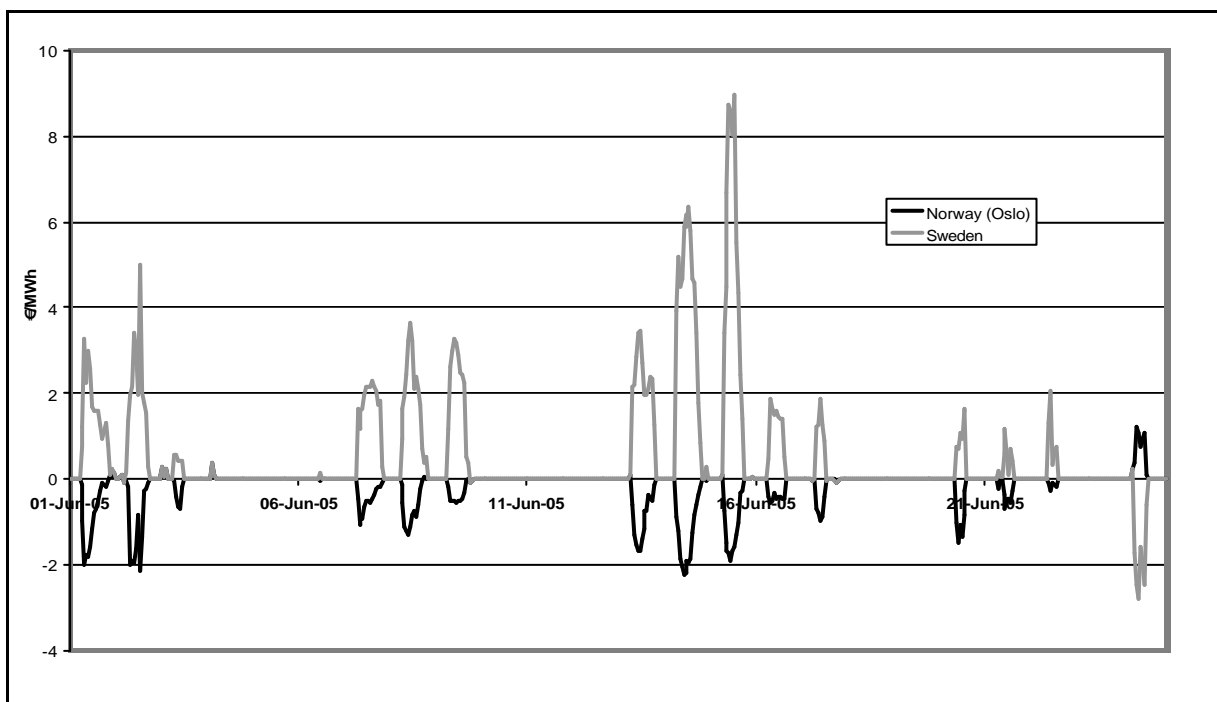
The result is inefficient under-utilisation of the capacity which exacerbates the current supply shortfall – and consequent high prices – within Spain. In June 2005, we estimate that nearly 10 per cent of capacity at times when it was economic to flow from France to Spain (around 70 GWh) went unused. In July 2005 to date, the corresponding unused capacity is around 92 GWh or over 16% of capacity that was "in the money" to flow from France to Spain. On a single day, (17 June 2005), we estimate that the unused capacity of 3.6 GWh cost the Spanish system a minimum of €560,000 (which, if scaled up for the two months would give a total cost for June and July of over €25 million).

2.2 Fixed-Priced Border Capacity Rights Are Essential to Cross-Border Competition

The ability to secure long-term cross-border capacity at a fixed price is crucial to the Commission's objective of effective cross-border competition and market integration. This should be unsurprising since, as with any other commodity or good, a remote competitor's ability to compete with a local provider is a function of both their cost of production and the cost for delivery. In the energy markets, while local producers, suppliers and consumers can lock in a fixed price on their local power exchange or bilaterally, the absence of long-term capacity rights at many borders currently prevents cross-border participants from competing on a similar basis simply because they cannot lock in the price of cross-border transmission.

The short-term price for transmission is incurred by cross-border traders either explicitly or implicitly. Where short-term capacity auctions exist, market participants will pay the difference ("spread") between the day-ahead expected prices in the two markets to acquire the capacity to move power between the two markets. In markets with market coupling, such as the Nordic markets, traders incur the difference in market prices implicitly, eg, a trader buying 100 MW in the Norway (Oslo) Zone and selling to Sweden would both long 100 MW in Norway (Oslo) and 100 MW short in Sweden which would require them to pay the Swedish zonal price and get paid the Norway (Oslo) price. Although they had bought and sold the power for a fixed price therefore, they would still be exposed to the difference between the Oslo and Swedish prices. As figure 2 below demonstrates for early June, this would have resulted in significant risk to the trader in making a physical delivery from Norway to Sweden, with the difference in these prices ranging from €0/MWh to nearly €11/MWh.

Figure 2: Difference between Norway (Oslo) & Sweden and Nordpool System Price



The risk associated with variable short-term price difference between markets significantly undermines competition across borders because traders find it difficult, impossible or very

expensive to lock in the price for transmission. In turn, this renders a cross-border participant uncompetitive with local suppliers when competing to supply a customer across a border. We have many customers looking to lock in prices for their power supplies for a year. However, without the ability to lock in the transmission price over a similar horizon, we struggle to provide a competitive offer given the resulting exposures to the price of transmission between markets. It is for this reason, that the ability to get a long-term fixed price for transmission is so important to effective cross-border competition.

2.3 The Market Will Not Provide Efficient Fixed-Price Transmission Hedges

Several TSOs have argued to us that the market can be left to develop the required hedges for the difference between locational market prices and that the primary focus of regulators and TSOs should be the provision of efficient spot markets and efficient cross-border congestion management (eg, via market coupling). The argument runs that, just as market participants freely trade to hedge their exposure to spot market prices over time, a market should naturally arise for market participants to hedge the *difference* or *spread* between the spot prices in different geographic markets. Despite its superficial appeal, this explanation is based on a fundamental misconception about the nature of trading.

The primary purpose of trading is to manage risk. In its simplest form a generator - who benefits when prices rise, but loses when prices fall – will sell at a fixed price to a supplier who has the opposite exposure to price (ie, loses when prices rise but benefits when prices fall). In this way the “long” generator can mitigate their exposure by selling to the “short” supplier. Trading intermediaries facilitate this process by aggregating purchases at different times and locations and subsequently disaggregating them for onward sale. This process may at times involve some speculation, eg, if prices are expected to fall traders may sell in advance of making the purchases. However, the fundamental role of traders is to effect an efficient transfer of price risk between buyers and sellers by allowing generators, suppliers etc to sell and buy what they want, where they want it and when they want it.¹

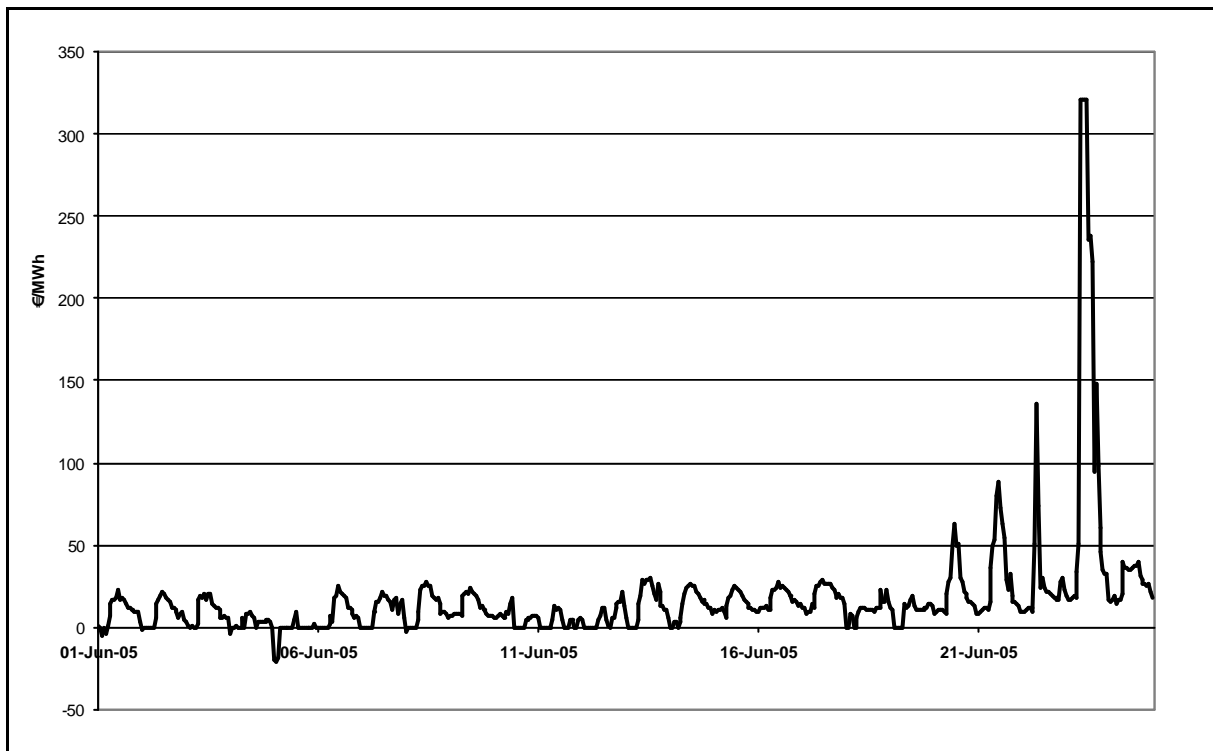
In the absence of transmission rights, market participants pay for congestion since the sellers into the exporting market receive a lower price than the buyers pay for the cross-border power flows in the high-priced importing market. As a result, market participants as a whole are “short” congestion since they lose money if congestion increases. The reason why a natural market in transmission price hedges will not arise is that is no corresponding market counterparty that is naturally “long” congestion, ie, who benefits when congestion increases. (The only parties which are “long” congestion are the system operators since they receive increased congestion revenues as congestion increases.) It is therefore impossible for market participants alone to effect an efficient transfer of risk between themselves since there is no natural counterparty (other than the system operators) who are looking to sell transmission rights forward to allow market participants to hedge their short position on the price difference between the two markets.

¹ Traders also help to overcome any credit constraints on market participants dealing directly with each other by acting as a credit-worthy intermediary.

In the absence of a natural counterparty to hedge the cross-border price risk with, any trading in locational hedges therefore involves pure speculation on the likely locational price differences. This significantly reduces the potential liquidity of this market, since few counterparties are willing to take solely speculative risk in the absence of an underlying “physical” market in the commodity particularly in circumstances where they have little ability to forecast and understand the underlying drivers of the congestion price differences.

There is practical experience of this phenomenon in Nordpool. Although Nordpool allows market participants to trade contracts relating to the spread between zonal prices these are highly illiquid, infrequently traded and with large bid-offer spreads. For example, on 26 July 2005, only 4 of the 26 locational contracts for differences traded at all, there were no bids or offers on 2 of the contracts and all but two of the remaining contracts had bid-offer spreads in excess of 20 per cent of the bid (with some rising as high as 200 per cent). This is unsurprising: despite the transparency and high levels of interconnection in the Nordpool market, the locational spreads can still be highly unpredictable and volatile as Figure 3 below illustrates with respect to the spread between the Denmark West and Nordpool System prices. In response to this risk, and with no natural counterparty to lay this risk off to, the market makers on the locational spread products are effectively forced into high bid-offer spreads merely to justify taking the associated risk.

Figure 3: Difference between Denmark West and Nordpool System Spot Price



Although Nordpool is rightly claimed as a benchmark for the development of an efficient liquid wholesale market, this obscures a crucial distinction between the liquidity on the Nordpool system market and liquidity in the underlying physical, regional markets in the Nordic region. The majority of trade in Nordpool relates to the unconstrained Nordpool system price rather than to zonal prices. Although market participants can achieve a

reasonable hedge for their local price exposures by trading financially at the Nordpool hub because zonal prices are *generally* correlated with system prices, it is significantly more difficult to hedge the differentials between the system price and their local price. As a result, the underlying physical markets for deliveries within Nordpool zones are significantly less liquid and it is prohibitively expensive for generators and suppliers in one zone to supply customers in another zone. This problem is likely to be significantly more onerous in other continental markets which are less well interconnected than Nordpool and where there are significant differences in the underlying price drivers between markets.

2.4 System Operators **Must** Offer Long-term Firm Cross-Border Capacity Rights

The previous section has demonstrated why the market cannot be left to provide efficient hedges for the price of transmission between markets, because of the absence of a natural counterparty in the market that is “long” congestion. The only parties that benefit when congestion increases – and hence the only potential counterparty to supply forward transmission price hedges - are the respective system operators since. It is for this reason that system operators **must** offer long-term transmission rights to market participants to allow them to hedge their cross-border risks and thereby facilitate effective competition across borders. By auctioning long-term transmission rights, TSOs not only allow market participants to lock in the price for transmission across borders but also stabilise their own congestion revenues. Given that these long-term rights are a fundamental requirement to developing cross-border competition, regulators should therefore **require** TSOs to auction long-term capacity rights for the entire cross-border capacity.

Unfortunately, the debate so far about reforms to cross-border competition has been unduly weighted in favour of short-term congestion management, as a means of optimising capacity usage and this is - to some extent - reflected in the Regulation’s focus on congestion management. This debate has often been cast in terms of a choice between implicit auctions (market coupling) and explicit auctions of capacity. This choice is illusory. Although market coupling may be a great way of optimising short-term capacity *usage*, it does not allocate transmission capacity to market users in a way that allows them to lock in the price of transmission over time. The truth is that you need both: efficient congestion management (eg, through market coupling) **must** coexist with long-term auctions for the maximum amount of cross-border capacity, if the benefits of cross-border competition are to be fully realised. Although long-term transmission rights are often presented as merely an optional “extra” to the market coupling model, without these rights, market coupling will fail completely to improve cross-border competition.

Fortunately, long-term transmission rights – whether physical or financial – are perfectly consistent with market coupling as means to optimise short-term capacity usage. This is straightforward in the case of financial rights which run in parallel with the underlying spot markets and hence do not directly influence the underlying optimisation of short-term power flows. However, even physical rights do not impede the optimisation of dispatch and capacity usage. A generator holding physical capacity from market A to market B has the following options approaching the day-ahead market:

- Firstly, the generator could choose to “use” the capacity by generating in market A and flowing the power from market B;
- If the generator is not planning to “use” the capacity by generating they can sell the capacity in the secondary market (at a price which reflects the expected difference in the market prices between zones);
- Alternatively, the generator may choose to schedule a flow from market A to B, but not to generate. This would leave them long in Market B and short in Market A, such that they continue to receive the difference between the market prices without actually using the capacity by generating (in this way, the “physical” schedule is effectively converted into a financial contract conferring the right to the price difference irrespective of actual “usage”). They might do this for instance if they have sold at a fixed price in market B, but find it cheaper to buy power in Market A than to generate in order to deliver on that contract.

In this way, dispatch should remain optimal even with physical rights. The only residual concern would be if the generator chose to not to sell the capacity and to not schedule a day-ahead flow such that the capacity remained unused. In this case, the system operator should “resell” any unused capacity explicitly (or implicitly under market coupling) to the market on behalf of the physical right holder. In this way, the right holder is kept whole for the value of the right that they own, but without being able to distort dispatch by leaving capacity unused. (Under market coupling, this would be equivalent to physical rights converting to financial rights at the point of nomination.)

2.5 TSOs Should be Obligated to Facilitate a Secondary Market

Whether rights are physical or financial, a secondary market is essential to allow market participants to optimise their cross-border portfolio over time. As their purchases, sales and generation in each market evolve market participants may need more or less cover for cross-border price differences. Active secondary markets ensure that short-term capacity is reallocated to those who value the capacity most over time, irrespective of the initial purchaser in the primary auction. (For this purpose, it is essential that say an annual right corresponds to a “strip” of 8760 hourly rights.) Although the Regulation provides for capacity to be freely tradable until the point of use, system operators will need to track who holds the capacity at different interconnections to establish:

- who ultimately has the right to schedule cross-border flows; and/or
- to whom they should send congestion payments (under financial rights.)

However, the system operator could – and should – also be an active participant in the secondary market to allow:

- system operators to “buy-back” capacity that they have previously sold to manage expected increases in congestion. This gives the system operators significantly more flexibility in managing congestion because they can choose to mitigate congestion in advance in addition to rebalancing generation in the spot or on-the-day markets. This

increases competition for “constraint management services” and should result in lower constraint management costs (as NGC has experienced in the UK);

- it would allow the system operator to release small amounts of further unexpected surplus capacity to the market without the need to organise a new primary auction of capacity.

As a consequence, system operators should be given an obligation to facilitate a secondary market in transmission rights by providing a platform which both acts as a registry of rights holdings and a means of transferring rights between market participants and/or the system operator.

2.6 Capacity Rights must be Long-Term

To ensure effective competition, market participants need to be able to acquire transmission rights which allow them to hedge transmission costs over similar horizons to their likely purchases and sales in different geographic markets. This is likely to require the ability to acquire capacity for several years into the future. For example, to meet the requirements of a customer tendering during the course of 2005 for supplies in the calendar years 2006 or 2007 a cross-border supplier would require the ability to obtain transmission capacity for calendar years 2006 and 2007 during the course of 2005.

Despite this requirement for long-term capacity, many of the current plans for primary capacity auctions focus on shorter tenors ranging down from a year, through quarters to the day-ahead (eg, the French-Spanish plans would allocate a third to each time bucket). However, the retention of capacity for day-ahead allocations translates into an inability of market participants to hedge their forward contractual positions (eg, cross-border sales) since portion of the capacity is only available spot. Although market participants may have shorter-term requirements for capacity as their generation and demand portfolio changes, these can be met through the secondary market rather than the primary capacity allocations. In deciding the tenors for allocating forward transmission capacity, there should be a presumption in favour of auctioning longer-term rights for several years into the future.

2.7 Capacity Rights Must be Financially Firm

The Regulation requires TSOs to offer capacity that is as “firm” as possible. While it is clearly impossible for system operators to guarantee the “physical” firmness of any transmission right (because of unexpected congestion and outages), it is essential that all forward transmission rights are *financially* firm to ensure that market participants can efficiently hedge their cross-border flows. Financial firmness requires that system operators compensate capacity holders at the full market value for any rights that are withdrawn.

Financial firmness would be automatically guaranteed with financial transmission rights, because market participants would continue to receive the price difference between the markets even if they cannot physically flow the power. However, with physical rights financial firmness would require the TSOs to pay users the price difference between the markets if their rights are withdrawn (essentially the TSO would need to “buy back” the capacity previously sold).

Without financial firmness, market participants competing across borders are left with the risk of paying the short-term price difference between markets in the event that transmission is withdrawn (because they would be left long in the exporting market and short in the importing market). This can leave market participants as price-takers in highly concentrated short-term markets, (eg, Denmark West or the E.On region in Germany in the event that Danish-German capacity is cut). This leaves market participants exposed to the potential exploitation of short-term market power and/or facing penal imbalance charges (which do not reflect the opportunity cost of short-term power). The inability to hedge these risks significantly undermines participants' ability to compete across borders with local suppliers.

2.8 TSOs Can Manage the Risks Associated with Selling Long-term firm transmission Capacity

Despite the need for long-term firm transmission capacity for effective cross-border competition, system operators have shown little inclination to sell capacity forward. In particular, they have argued that they cannot sell transmission capacity forward because availability of transmission capacity depends on the scheduled power flows (which in turn depend on the available capacity). This so-called "chicken-and-egg problem" is not a valid argument for not selling transmission capacity in advance. Just because we don't know whether the chicken came before the egg – or vice versa – it does not follow that we don't still have chickens and eggs. Similarly, just because we don't know what the actual capacity is until we know the actual flows, it does not follow that system operators cannot sell the majority of capacity in advance. There are two reasons for this:

- While the precise amount of capacity may be unknown in advance, TSOs are in a good position to forecast capacity availability. A fixed endowment of plant - and associated fuels – accurate demand forecasts and knowledge of the transmission system's configuration should enable system operators to forecast accurately the likely availability of transmission capacity (particularly if there is cooperation and information sharing between system operators in neighbouring regions). Although, on any one day, these forecasts may prove inaccurate, on average they should be highly reliable.
- More crucially, the decision on how much capacity to allocate in advance is a commercial decision and not a technical one. In real time, the imperative to meet operational security standards means that actual flows will face the same constraints irrespective of the amount of capacity previously allocated. Allocating more capacity in advance therefore translates into an increased commercial requirement for system operators to rebalance flows in the light of actual system constraints. Rather than imperilling the technical security of the system, restricting advanced sales of capacity leaves system operators with a valuable, free, commercial option on whether to release further capacity over time.

Aside from the chicken-and-egg problem, our discussions with system operators have revealed an unwillingness to take the risk associated with selling transmission capacity forward and compensating users for the withdrawal of their transmission rights. We believe these perceived risks are overstated because:

- Selling transmission rights actually reduces TSOs risks since, in the absence of long-term rights, they face variable congestion revenues (and/or variable revenues from short-term sales of capacity):
- TSOs only face any downside if the actual transmission capacity available is *on average* below that which they have previously sold to market participants (which is pretty unlikely given system operators' conservatism in calculating levels of available capacity)
- The revenues that the TSOs receive in return for the long-term firm rights should reflect expected levels of congestion and on average will therefore be sufficient to cover the costs of guaranteeing the firmness of those rights.
- TSOs are regulated businesses and hence any surplus or deficit (if at all) from selling transmission rights and managing congestion will roll into their regulated revenues and costs and leave no residual financial exposure.

2.9 The Regulatory Framework Must be Strengthened to Promote Competition

Despite the low risk, system operators still have little appetite to take any risk by selling long-term firm transmission capacity to market participants. This unwillingness is somewhat surprising; generally businesses are more than willing to sell their product (in this case, transmission services) on a long-term basis to their customers. Moreover, it is not entirely unreasonable to expect customers to want compensation equivalent to the liquidated damages that they have suffered if the product that they have bought is not actually delivered. The problem is that system operators have little inclination, and no incentive, to do otherwise. They see their jobs solely as securing the transmission system rather than as providers of an essential commercial transmission service to the internal EU electricity market. This results in:

- Overly conservative (low) levels of capacity allocations;
- Sub-optimal usage of the actual cross-border capacity (because it is not released in timescales consistent with the bulk of market participants' purchasing and sale decisions);
- The absence of effective cross-border competition because of the inability of market participants to hedge a cross-border position;
- Poor incentives for system operators to operate and maintain the transmission system in order to mitigate congestion (since the costs of increased congestion can be passed through to system users);
- A positive incentive for system operators to use interconnection capacity as a free source of operating reserve to avoid the cost of paying for spinning reserves on generation (since market participants, rather than system operators, face the costs of curtailment);
- Little incentive for system operators to exchange information with and coordinate system operation with neighbouring TSOs to improve the efficiency of the system as a whole;
- An inexorable slide towards short-term allocations with the revenues being used to reduce tariffs rather than to guarantee capacity and/or build new capacity as provided for in the Regulation.

The overall result is widespread operational inefficiency and imperfect competition in the internal EU electricity market. To solve these problems the regulatory framework needs to be strengthened to provide regulators and system operators with appropriate obligations and incentives to promote competition including:

- an overriding obligation on national regulators and system operators to promote effective competition in the generation, supply, purchase and sale of electricity in the EU internal market;
- place an overriding obligation on system operators to operate their transmission systems efficiently, economically and on a coordinated basis with neighbouring system operators;

These obligations should be supplemented by an obligation on regulators to provide the system operators with incentives to maximise the availability of cross-border capacity, to sell that capacity long-term and, hence, to operate the system efficiently. Although system operators are likely to remain regulated monopolies, the experience in the UK suggests that enhanced regulated rates of return for “doing the right thing” for competition can lead to significant reductions in operational constraints and the adoption of a commercial, market facing approach to the provision of transmission services.

The cross-border Regulation and/or the associated guidelines should also be amended to require:

- TSOs to sell (rather than merely “make available”) the maximum feasible volume of interconnection capacity forward with a presumption that the majority is sold long-term forward and only *de minimis* volumes are retained for short-term (eg, daily) allocations;
- Financial firmness of forward capacity sales;
- System operators to maintain a transmission capacity holdings registry and to facilitate a secondary market in transmission capacity (which the system should also be able to use to buy-back capacity to manage congestion and/or release any residual available capacity);
- An explicit hierarchy for the use of congestion revenues, ie:
 - The priority should be to underwrite the firmness of *existing* transmission capacity (either by compensating users for withdrawing capacity or investing to alleviate congestion);
 - Once existing capacity has been guaranteed, the revenues should be used to expand capacity to reduce congestion
 - Only where there is any surplus from the previous two uses should any surplus be used to reduce domestic tariffs.

3. Greater Transparency on Market Fundamentals is Essential

Barclays Capital has long been a public advocate of greater information transparency as a means of stimulating competition and liquidity in EU electricity and gas markets. As such we fully support EFET's position paper on the topic² which sets out the many benefits of greater information release. We will not repeat those arguments here, but would note that, despite the importance of this issue to the development of competition and enhancement of security of supply, there has been little progress in Member States in releasing more information since the publication of that paper in July 2003. We also note that the requirements of the cross-border regulation relating to the calculation and publication of forecast cross-border capacities have yet to be applied in all but a handful of jurisdictions. Given the importance of this issue to market integration and the development of competition in European energy markets, we would offer two potential motivations for this widespread inertia:

- Firstly, that regulators have generally failed to appreciate the scale of the benefits that information release might secure; and
- Secondly, there is widespread opposition from producers on the grounds that greater information release would compromise commercial confidentiality.

These problems have made it difficult for regulators to challenge the status quo and to release more information. However, while it is significantly easier to measure the costs of greater information release than the associated benefits, attempts to demonstrate the scale of the benefits in the UK gas market indicate that the benefits are likely to be several orders of magnitude greater than the costs. Moreover, concerns about commercial confidentiality are often overstated and, in the two years since the publication of the EFET paper, have been overtaken by the emergence of commercial providers of physical generation data. We expand on these two issues in the following two sub-sections, before restating the information that we would like to see released in section 3.3.

3.1 The Benefits of Information Release

The potential benefits from greater information release are an order of magnitude greater than the associated costs. In practice, however, the problem faced by regulators is that the benefits can be difficult to quantify, whereas the purported "costs" are all too readily volunteered by those with an interest in maintaining the status quo. Measurement difficulties, however, do not necessarily equate to an absence of those benefits and although precise calculations are difficult, it is nevertheless possible to estimate the likely magnitude of the benefits and costs. In this respect, the debate surrounding information release in the UK gas market is instructive.

Although the onshore gas market in the UK compares favourably with other EU gas markets in respect of competition and liquidity, the offshore production arrangements have traditionally been very opaque with little, if any, information on offshore production capability,

² "Transparency and Availability of Information in Continental European Wholesale Electricity Markets", July 2003.

maintenance outages and actual flows made available to the wider market and to the system operator (Transco). Ofgem, has been a consistent advocate for greater offshore information release and during the course of 2003, Ofgem – in consultation with the Department for Trade and Industry, offshore producers and industry participants - examined the case for releasing a greater range of information to the market. As a contribution to this debate, Barclays Capital sought to estimate the impact of greater release of fundamental physical production information in the UK gas market³ with the following results:

- Benefit from increased competition in production and supply: > £45m per annum;
- Benefit from better coordination of transport and production outages: £20m per annum;
- Benefit from more efficient risk management: = £200m per annum;
- Improved security of supply: not assessed, but potentially very large value;
- Reduction in balancing costs: not assessed, but significant
- Transferring the commercial value of information to consumers: not assessed but significant.

According to our estimates, therefore, releasing more information on UK offshore gas production alone could save UK gas customers at least £265 million per year in increased competition, reduced trading risk premiums and better coordination of production and transmission outages.⁴ This translates into a present value to consumers of £2.65 billion – or nearly €4 billion (at a 10 per cent discount rate). Given the materiality of the non-quantified elements, however, the true benefit to UK gas consumers is likely to have been significantly in excess of this. Given that the UK gas market is still relatively competitive, liquid and transparent when compared with many European gas and power markets, the cost to EU energy consumers of poor information transparency alone is therefore likely to run into tens of billions of Euros.⁵ Given the magnitude of this potential benefit, the continued failure to release sufficient information on supply and demand fundamentals in EU energy markets should be addressed as a matter of urgency.

3.2 Confidentiality concerns are not sufficient to block greater information release

Despite the magnitude of the benefits associated with greater information release, there has nevertheless been significant opposition to greater information release on the grounds that it would undermine generators' commercial confidentiality. However, it is crucial here to

³ "Benefits from Greater Information Release in the UK Gas Market", Barclays Capital, December 2003. (Attached).

⁴ Although we didn't assess the direct costs – in terms of the associated IT systems – these are small by comparison, ie, of the order of millions or less, rather than tens of millions.

⁵ The consultation during 2003 was followed by a voluntary agreement between the DTI and the offshore producers to release certain categories of production data to Transco and to the wider market. A recent proposal from energywatch (the energy consumers' representatives) has sought to disaggregate some of that data further to provide more detailed information on real-time sub-terminal gas flows. Ofgem have issued an assessment of the costs and benefits of this proposal which also provides a useful template for assessing the costs-benefits and risks of further information disclosure which can be found here:

http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/11579_14305.pdf

distinguish between ex ante information on production and maintenance plans which can justifiably be claimed to reveal information about a market participant's commercial position and prompt ex post information on actual production and flows. In the former case, concerns about confidentiality can be addressed by aggregating the data (eg, by fuel type or region) to provide the market (and system operators) with useful planning data while not revealing an individual producers commercial plans.

These confidentiality arguments are less relevant when one considers the release of information on actual production whether promptly (close to real-time) or ex post with some delay for the following reasons:

- **Trading is a zero-sum game.** The main argument against the prompt release of actual production data is that producers should be able to buy in the market to cover an outage before the market more widely has a chance to factor the impact of the outage into prices. However, it should be remembered that trading is a "zero-sum" game; if one party gains from buying in advance of a supply shortage and associated rise in market prices, then, by definition, the selling party must lose the same amount. The failure to reveal real-time production information therefore effectively represents a direct transfer of value from market participants (and ultimately consumers) to producers. It should therefore come as no surprise to policy makers that producers vigorously oppose plans to reveal real-time production data. A simple thought experiment confirms this view: if the status quo was to release prompt production data, would anyone seriously entertain a move back to allowing producers to buy in the market on the basis of private information in advance of a market response to the supply shortfall? In this regard, it is instructive that, in 15 years, no attempt has been made to remove prompt generation information in the UK or Nordic electricity sectors to protect the position of generators largely, one suspects, because it would be difficult to mount a credible case for such a change.
- **Even ex post data would be invaluable to the market.** Even if one accepts the producers' arguments with respect to real-time data, there can be no argument about releasing physical production data on a unit-by-unit basis after the event, since by definition it will no longer reveal any commercially sensitive information about a producer's future commercial position. Nevertheless, even the delayed release of physical production data would be invaluable to wholesale market participants in analysing why prices moved in particular ways on particular days and, hence, as a basis for forecasting future prices and quantifying the associated risks. We now get many requests from EU energy consumers asking for supply contracts and price hedges. However, without information on the likely supply and demand fundamentals and how these have influenced prices in the past, we struggle to produce robust forecasts of prices on which to base these offers. This puts us and consumers at a disadvantage, relative to incumbents, as forward hedging becomes both unduly risky and costly.
- **Physical power production data is now available commercially in any case.** In the two years since the publication of the EFET paper, things have changed significantly. In particular, information on actual generation is now available through commercial information service providers which use remote monitoring technology to collate data on

the output of individual power stations.⁶ The significance of these developments is that much of the data previously claimed as commercially confidential is now available publicly which removes the main barrier to system operators releasing this information to the wider market. However, although the presence of information service providers now provides a route for market participants to obtain information on actual production, it does not in itself satisfy the market's information requirements and, in short, we believe this function would be better handled by system operators. Information service providers can offer only partial system coverage and, yet, in the current market charge high prices for this limited service. The prohibitive level of these prices means that, in practice, this data is currently only available to a sub-set of market participants which introduces a huge effective barrier to entry for smaller players into the wholesale power market and effectively forecloses the wholesale market to all but the incumbents and very largest traders. The solution would be for system operators to publish the required set of data to the entire market.

In summary, the arguments against prompt information release on the grounds of confidentiality give producers' interests undue weight when compared to those of consumers and this data is no longer confidential in any case (albeit access is limited to major market participants. Moreover, even if the regulators accept the arguments against prompt release, there, there is still no justification for not releasing detailed unit-by-unit production data after the event.

3.3 A Strategy for Greater Information Release

Given the benefits of information release and the need to level the playing field with respect to access to that data, the Commission should therefore develops proposals to encourage – or even mandate – regulators to secure greater release of information. Specifically, we would ask the Commission and European energy regulators to work with electricity system operators to secure the release of:

- Prompt ex post publication of actual generation on a unit-by-unit basis;
- Real-time publication of available capacity by generating unit;
- Standing data on the capacities of installed production together with scheduled additions and closures of capacity to aid long-term forecasting. (NGT's "Seven Year Statement" provides an example of the type of report that would be useful.)
- Forecast generator available capacity from the day-ahead to several months in advance. Aggregated, as appropriate (eg, by fuel type or region) to protect the forward commercial position of individual companies. (Similar forward information is available in aggregated form in the UK and Nordic markets.)
- Ex ante forecasts of demand, physical transmission capacity and available transmission capacity, including information on any quantities reserved for long-term contracts;

⁶ Further details on these providers can be found here.

<http://www.genscape.com/na/index.shtml>

<http://www.entras.ch/>

<http://www.powerproduction.org/>

We would also expect similar levels of information in the gas sector with the addition of information relating to physical injections and withdrawals at individual storage facilities.

4. Markets Should be Extended Within-Day

The EU is currently characterised by a multitude of different arrangements for the national wholesale markets, allocation and management of cross-border flows and for balancing energy flows. This can present several difficulties for market participants seeking to compete within national markets and across the borders between those markets, for example:

- Day-ahead capacity auctions, power exchanges and nomination deadlines all fall at different times, which effectively imposes a trading “cascade” where market participants have to close out any residual positions in markets which close later. While this can be seen as concentrating liquidity in the later closing markets, it also gives local generators with flexible plant within the last market an inherent commercial advantage in the wider internal EU market.
- The cascade of markets creates the need for a trading team to ensure coverage across the entire day and on non-working days, which raises a significant barrier to the entry of smaller trading participants.
- Different market timetables can limit market participation across borders, eg, although some markets allow intra-day trading up to 1 hour ahead of delivery, others have limited intraday sessions or confine the intraday activity to local balancing actions. This limits the ability of the market to optimise flows within the day between national markets.
- Interconnector flows – and hence cross-border participants - are often unable to participate in national within-day and balancing markets which again limits the market's ability to optimise flows between national markets.

The textbook solution to these difficulties would be to adopt a “standard market design” which would apply a common timetable and rules to all markets. This approach has been adopted in the North-East United States with the PJM market which closely mirrors FERC's standard market design. Nordpool also applies a standard market design across the Nordic region (although short-term balancing remains the responsibility of national TSOs) and the Elbas system in particular provides an aspirational benchmark for remainder of the EU internal market in its provision of a seamless, coordinated platform for within day trading across the Nordic region.

While the adoption of market-coupling arrangements will move some regions within Europe in a similar direction, it is highly unlikely that the EU will – or indeed should – adopt a common market design for all elements of the trading arrangements. It would be difficult, potentially impossible, to reach agreement on the precise details of such a market and national TSOs are likely to want to retain some direct control over local rules (particularly over balancing as in Nordpool). Neither is it necessarily desirable to adopt such a design, since the economic characteristics of different markets – in terms of fuel mix and plant dynamics – may lead to differences in the “optimal” dividing point between unrestricted competition and the point at which TSOs should take over to balance the system and manage constraints (ie, there may be optimal timings for gate-closure in different markets). This optimal dividing point should be set as close as possible to delivery, as market participants are best-placed to manage their intraday trading and balancing requirements themselves.

Faced with these difficulties, the key to integrating EU markets successfully is not necessarily to prescribe a uniform solution, but to maximise the opportunities for the “market to work” by moving to dynamic, flexible, continuous and inclusive trading arrangements which maximise the ability of market participants to optimise their positions and hence maximise the scope for the market to balance supply and demand approaching delivery. This would primarily be achieved by broadening the scope of the market to introduce continuous trading within day and to move gate closures as close as possible to the point of delivery. Such a market would be based on the following sequence of key building blocks designed to optimise the scope for optimal trading and incorporate maximum flexibility while respecting the TSOs’ need for certainty over market participants’ plans so that they can economically balance supply and demand and manage other system constraints:

1. **Cross-border capacity allocation.** Forward auctions of cross-border transmission capacity (whether financial or physical).
2. **Over-the-counter and bilateral trading.** Long-term to short-term trading between market participants
3. **Day-ahead power exchanges.** Centralized clearing (potentially through market-coupling) for additional purchases and sales within each market.
4. **Day-ahead nominations** of physical deliveries and offtakes made up of OTC and bilateral trades, traded power exchange volumes, physical generation and consumption plans and usage nominations for cross-border capacity (with physical transmission rights)
5. **Cross-border capacity reallocation and trading.** Where physical transmission rights are used, following the day-ahead scheduling, TSOs should reallocate any unused or previously unallocated capacity for use within day and allow market participants to reallocate their capacity holdings. This would preferably be achieved by an ongoing screen-based “capacity trading” facility which would allow market participants to exchange entitlements to the cross-border capacity and/or the TSO to buy and sell capacity, eg, to manage within-day congestion by repurchasing capacity or to release capacity that becomes available within day as a consequence of favourable flow schedules (including counter-flows).
6. **Intraday trading.** Continuous and rolling gate closures within day, eg, 1 hour before the start of each hour of the day, with market participants having the option to renominate their delivery schedules right up to each gate closure (where those schedules would need to be consistent with their final capacity holdings). (Points 5 and 6 can be integrated into one continuous intraday trading platform where transmission rights are financial and capacity is allocated “implicitly” via coupled markets, eg, as happens in the Elbas system in the Nordic region.)
7. **Balancing.** Following gate-closure, the TSO would execute balancing transactions to manage the system balance and any residual system constraints within operational timescales. While we would expect the main participants within the balancing markets to be generators and flexible consumers within each national TSOs control area, TSOs should investigate methods for allowing wider participation, eg, by allowing cross-border participants to offer balancing power and other ancillary services.
8. **Imbalance settlement.** Following delivery, any imbalances between participants net physical deliveries/purchases and consumption/sales would be settled at cash-out prices which reflect the marginal cost of the actions taken by the system operator to balance supply and demand in operational timescales. Wherever possible, the price of actions taken purely to resolve locational constraints in sub-regions of the market should be omitted from the determination of national or regional balancing prices.

This dynamic and “flexible” approach has several key advantages over the current static arrangements:

- It would allow cross-border participants to play a greater role in the optimisation of markets within day and in balancing timescales, therefore increasing the efficiency of the markets;
- Markets participants could freely choose the timescales over which they optimise and close out their own positions which will reduce barriers to entry by allowing market participants to choose when and where they trade out their positions;
- Liquidity and trading will flow to the most efficient and economic markets rather than being constrained by the market timetable.

5. Regulating for Competition

The measures we have outlined above with respect to cross-border competition and information transparency will significantly enhance competition in European electricity markets. In turn, more liquid and competitive wholesale markets are a necessary condition for facilitating entry into local generation and supply markets. Nevertheless, many EU national markets remain heavily concentrated on both the generation and supply sides and this has impeded competition despite the comprehensive EU legislative framework underwriting liberalisation. To this end it is crucial that the structural provisions of the directives are rigorously enforced to ensure effective unbundling, seamless third-party access to networks and effective new entry into the generation and supply markets. The competition investigations currently being undertaken DG TREN and DG Competition are also a valuable opportunity to analyse the key barriers to competition that currently exist and, we look forward to any pro-competitive initiatives stemming from these investigations.

Absent radical restructuring of the sectors, in the meantime, it is important that further consolidation is subject to intense scrutiny and that those measures designed to improve competition, such as the release of capacity through VPP auctions, work effectively. It is also important that customers enjoy a genuine choice of supplier and that regulatory measures to protect the environment or to underwrite security of supply do not impede effective competition in the markets. We address each of these themes in turn in the following sections.

5.1 Improving the Efficacy of VPP Auctions

Some Member States (eg, France, Belgium) have sought to address generation concentration through Virtual Power Plant auctions (VPPs) which release capacity to competing market participants as a basis for improving competition and liquidity within these markets. While VPPs have been a welcome innovation and have led to some improvement in competition and liquidity, several factors constrain their usefulness and limit their contribution to improving competition in the price-setting portion of the market. For example:

- **The *perception of dominance (whether or not it is exercised) limits VPP participation.*** Any party acquiring power in the VPP effectively faces the commercial risk associated with having to sell the acquired power back into the market at wholesale prices which remain under the direct influence of the party releasing capacity. The mere risk that these prices can be manipulated adversely – whether or not this happens in practice – can be sufficient to prevent a market participant from opening a long position in that country and carrying the associated market risk.
- **An inability to acquire corresponding cross-border capacity can prevent participation in VPPs.** Market participants can mitigate their exposure to local market prices if they –can acquire cross-border capacity to move the power acquired through the VPPs out of the country to neighbouring markets. This allows market participants to place a “lower bound” on their exposure which can mitigate the risk sufficiently to make it viable to acquire the VPP long position. For example, in the case of the French VPPs, the option to sell the power acquired into neighbouring markets provides useful protection against the

risk of adverse movements in the French wholesale price. By contrast, in the Fifth Round of the Belgian VPPs, this option was not available to participants because the cross-border capacity auctions took place several weeks after the VPP auction on 18 November 2004. In the absence of the protection provided by interconnector capacity for 2005 and with no guarantee that we could acquire the required capacity at reasonable prices, the market risk associated with VPP participation was simply too large to allow our participation in the VPP. (Clearly the continuance of the “priority list” allocation at the French-Belgian border also does little to alleviate this problem.)

- **VPPs Strike Prices have often been too low to stimulate active competition at the margin.** To provide effective competition, VPP positions must translate into active participation in setting wholesale prices. This requires VPP holders to have the option to “generate” or “not to generate” at or around the prevailing market price. However, our experience is that the strike prices of VPP offerings place them deeply in the money. While putatively based on the marginal costs of production, the strike prices are often so low as to make it virtually impossible for the option to “generate” not to be exercised. Commercially, the “options” therefore largely equate to a forward purchase of power together with the associated local price risks described above.
- **The Tenor of the VPP Blocks can restrict participation unduly.** VPP structures can unduly limit participation by restricting the range of products that market participants can bid for. For example, the Fifth Belgian VPP offered capacity in 3, 6, 12, 24 or 36 month blocks from a common start date. Any participant seeking to acquire the calendar year 2007 would therefore be required to buy calendar years 2005 through 2007 and then sell out the position in years 2005 and 2006. This requirement to buy a sizeable block in order to acquire a position for a shorter, discrete period unduly constrains participants’ appetite to participate in the auctions because of the additional market and credit risk that must be borne in buying larger tranches of capacity.

To be effective, therefore, VPPs need to be part of a broad package of measures to improve competition and liquidity since they may not be sufficient in themselves to build liquidity. In relatively concentrated markets, the availability of cross-border capacity over timescales consistent with the VPP offerings is critical. Straightforward changes to the structure of VPPs (with respect to strike prices and available tenors) can also significantly improve participation and hence the contribution of the VPPs to improving competition and liquidity.

5.2 Customer Choice Must Become a Reality

Competition to supply final customers is a key element of the liberalisation agenda. While the focus is often on wholesale market competition and liquidity, retail competition is essential to underwrite competition further up the supply chain since the ultimate threat of losing customers is ultimately what will drive retailers to purchase efficiently from generators actively competing for their business and to actively manage their volume and price exposures in the wholesale market.

Unfortunately, effective retail competition remains largely a theoretical possibility in many Member States and there are a range of potential concerns in this area, for example:

- In Germany, the failure to adequately unbundle network operations means that potential suppliers have to negotiate a plethora of pancaked transmission tariffs to get a supply to the customer. The new German Energy Law should improve this situation materially, although the exemption for distributors serving less than 100,000 customers is likely to continue to prevent a significant number of German customers from enjoying full competition (despite this being consistent with the Electricity Directive).
- In Spain, regulated tariffs are currently below the economic costs of supply which is driving non-incumbent retailers out of business. While customers may be enjoying lower prices as a result, the cost of this in terms of the destruction of the competitive supply market in Spain is huge. Regulated tariffs should remain a backstop to protect against the abuse of market power in the transition to fully effective competition. For them to become a substitute for and to actively undermine competition, as they have in Spain, completely undermines the driving purpose of the liberalisation agenda.
- We are concerned about recent reported developments in France where a consortium of large users has formed with the express aim of obtaining “discounted” rates from the main utilities. While on the face of it there is nothing wrong with large users tendering for their requirements long-term and, thereby attempting to achieve lower rates, we are concerned by the lack of transparency surrounding these developments and the involvement of the French Ministry. We would be particularly concerned if the result of these discussions was the supply of power below economic cost to these users under an arrangement which excluded other potential purchasers and/or resulted in a cross-subsidy from smaller users who are yet to enjoy the benefits of full competition.
- Not only must customers enjoy the theoretical possibility of switching, significant effort also needs to go into the infrastructure to register the movement of customers between competing suppliers and to inform and educate customers about the switching process. The Commission should therefore consider whether further obligations on distribution system operators to provide a central platform for registration and customer transfer are appropriate.

5.3 Security and Environmental Policies Should Preserve Competition

Recent supply failures, although predominantly network related, have led to heightened concern about whether markets alone can deliver sufficient capacity to underwrite supply security. Despite evidence that markets are indeed delivering significant new capacity, it seems likely that, in future, Member States will consider intervening in the markets to manage installed capacity levels. The “public good” nature of energy security provides some theoretical economic backing for this intervention since for many customers, meters are not sufficiently sophisticated to measure consumption at particular times of the day and disconnections cannot always be targeted at those retailers and customers who have failed to purchase sufficient energy. Market price signals alone may therefore not deliver the desired

levels of security. There are three broad categories of instrument that can be used to address this problem:

- An obligation on suppliers to purchase capacity in addition to their underlying energy purchases;
- System operators purchasing a capacity margin to protect against interruptions;
- “Scarcity pricing”, ie, the inclusion of the value of losing load (VOLL) - which should equate to the value of additional capacity - into energy prices.

These instruments can, however, present significant problems which can undermine liquidity in the underlying power and gas markets. For example, the establishment of parallel capacity markets would draw the liquidity from the basic energy market. Payments for “available capacity” defined as a separate product from energy output, can also be open to manipulation and be difficult to enforce. TSO reserve purchases can also dampen peak prices, promote the early closure of plant that has not been contracted to provide reserve and undermine incentives for customers and suppliers to procure new capacity. This could result in the TSO procuring ever expanding reserve volumes, the progressive unwinding of the competitive portion of the market with little overall improvement in security of supply.

As regulators strive to bolster security of supply, the key will be to ensure that any measures maintain the integrity of the underlying energy markets and that consistent price signals are sent to the market at times of relative scarcity either directly - through scarcity pricing – or indirectly by ensuring that the full economic cost of any TSO reserve purchases is borne by those market participants who rely on the TSO procured reserve to cover their own requirements.

Similar considerations apply to the development of environmental policies in terms of the development of renewable technologies, the promotion of energy efficiency etc. It is particularly important that these policies work alongside and do not substitute for the underlying power market, for example:

- The risk of potential distortions should ensure that underlying signals as to the value of “brown” electricity at particular times and in particular locations is still accounted for in the dispatch and location of renewable technologies. The growth of wind generation in Northern Germany for example has already led to potential distortions to cross-border flows between Germany, the Netherlands and France (as discussed above). In this respect, market-based schemes (such as the renewables obligation in the UK) are likely to be more efficient than feed-in tariffs.
- There is no inherent reason why energy efficiency services need to be provided by the incumbent (or indeed competing) electricity supplier. However, there have been discussions in the UK about reducing consumers’ ability to switch suppliers on the grounds that suppliers need long-term contracts to recoup the cost of any energy efficiency investments. This type of rule would effectively sterilise completely the aims of the liberalisation directives. It is therefore important that any energy efficiency services are provided on an unbundled basis to customers so that they can still choose to switch supplier, while continuing to pay for any energy efficiency investments separately (eg, the

contract for an energy survey, the installation of an energy efficient boiler etc should not be tied to the underlying gas supply).