Target Model for the European Natural Gas Market

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Executive summary

One of the main aims of the 3rd Energy Package is to complete the European internal market in natural gas. Key to achieving this is ensuring that there is an effectively functioning wholesale gas market in Europe, where different sources of gas can compete. To this end, the 3rd Energy Package creates the concept of European Network Codes, which would apply throughout Europe and describe (among other things) key aspects of the framework for the wholesale gas market. This would include the way in which those with gas will get it to customers, the way in which trading will work, and the extent and nature of competition.

The European regulators, at the request of the European Commission, have launched a consultation process to define a "target model" for the gas market. This market model would set the framework for the development of the Network Codes. This report considers the objectives of a target model and provides a possible vision for the model, and this summary sets out some of the key characteristics of this model, and some of the key debates in its design.

The overall objective of completing an efficient internal market for gas is clearly in customers' interests. However, we demonstrate that the devil is in the detail. Depending on the approach taken, we believe European customers could end up beneficiaries of greater competition for the supply of gas and more efficient use of gas infrastructure, or paying billions of Euros for infrastructure which is not necessary, and paying a premium to attract investors to the gas sector.

We argue that Regulators and the Commission must be clear that customers' interests are at the heart of the design of any target model. In particular, in defining the target model, it may be important to notice that (a) competition is a means to further customers; interest, not an end in itself, (b) there can be conflicting objectives in defining the way in which producers can get their gas to market, (c) there is a risk in simply adopting approaches used in the electricity markets, and (d) the timing of implementation and future evolution of the market must be taken into account.

Competition as a means, not an end

Almost the starting point for the target model is the division of European into geographic regions within which different sources of gas (e.g. Norwegian, Russian) can compete freely. We consider the approach to defining such regions, and conclude that ensuring that all sources of gas can compete freely with each other should not be a goal in itself. It is unrealistic to assume that all gas sources will be able to compete to serve all customers in Europe, as this would require a gas transport network with huge capacity. For example, while gas supplies to GB might be able to compete with gas supplies to Ireland, it would cost much more to ensure that supplies from North Africa could compete throughout the continent with supplies from Norway.

Some contributions to the debate on the gas target model have taken the starting point that bigger regions are necessarily a good thing because they provide for more competition. We demonstrate that this is not necessarily in customers' interests, showing that there is a trade-off to be considered between the cost of infrastructure on one hand and the customer benefits of access to a variety of sources of gas on the other.

There are significant benefits from competition which can come from the creation of regions where all gas sources can compete freely (true "entry-exit" regions). This is preferable to designing larger regions but restricting the extent of competition within them. However, to ensure customers get the maximum overall benefit, we suggest that a case-by-case approach is needed to the definition of regions, based on robust cost-benefit analysis.

Moving gas from producer to consumer: conflicting objectives

Access to the gas network to allow producers to get their gas to customers is clearly of critical importance. Gas networks are typically regulated natural monopolies, so regulation must ensure that they make capacity available in a way which is:

- attractive to producers, in order that Europe can secure its gas;
- attractive for investors in the network, to ensure that required network developments can be financed;
- supportive of competition, so that customers receive the best price possible for their gas supplies; and
- fair for customers, so that customers do not end up paying for network investments which benefit other people.

We demonstrate that it is not necessarily possible to fulfil all of these objectives at once, and that a balanced view must be taken across them.

Europe competes with other markets to secure its gas. European operators and regulators have much less influence over the nature of this competition than is the case within Europe. We note that while long term contracts are often considered as being bad for competition, if this is the basis on which producers outside Europe sell gas, it may be important for European networks to sell transport services on the same basis.

If they do not, producers may perceive a risk of being left with gas which they cannot transport (and hence sell to European customers). If, as a result, producers take the view that Europe is becoming less attractive as a market, customers will end up facing the risk of higher prices, and needing to pay a premium to secure supplies. Such a price risk could be significant, because the costs of the gas commodity itself make up a large proportion of the costs paid by final customers for gas supply.

We make clear that well-intentioned rules aimed at promoting competition can lead to higher costs for customers overall. For example, in some countries, companies who have rights to use the network are required to give up these rights if they do not use them sufficiently. This can lead companies to use the network inefficiently (meaning customers may not be offered the lowest cost sources of gas) just so that they maintain their rights. We highlight alternate arrangements which may secure the same outcome without such problems, and which could therefore form a preferable starting point.

We also note that regulatory decisions which may seem to be in customers' interests in the short term can have damaging impacts in the longer term. For example, from a customer-value perspective it may seem perfectly reasonable to reduce the regulated revenue of infrastructure investments which are not fully utilised. And if investors put up their money knowing that this would be a risk, there may be no problem. However, if investors believed they would earn a regulated return irrespective of the degree of use over the lifetime of the asset, then such regulatory behaviour will undermine confidence in the regulator. Future investors will then demand a risk premium associated with their investments, and this premium will be picked up by customers in their gas bills.

For cross border flows of gas, we make clear that there will inevitably be some tension between encouraging competition between sources of gas in different countries while making sure that those who use the pipeline network to cross countries pay for it and do not leave national customers to pick up the bill. We indicate that a pragmatic solution will be required to balance these objectives.

Don't just say "they do it in electricity"

The market arrangements in electricity are often perceived as being "more advanced" than those in the gas market. However, we argue that there is a danger in importing arrangements which have been implemented in the electricity sector without considering the differences between the sectors.

For example, in electricity there is a well-established process of holding auctions for the sale of power a day ahead of the time of delivery. There is now a trend to using such auction processes across countries to facilitate cross-border trade.

However, the costs of electricity generation are relatively easy to predict at the day ahead stage, as a function of fuel prices at that time and power station efficiency. Equally, because electricity network operators must balance electricity production and consumption every second (i.e. balancing must be "instantaneous"), they need to understand the plans of producers and consumers well ahead of the actual time of delivery and plan for a wide range of eventualities (e.g. forecast errors, plant failures etc.)

Neither is the case in the gas network:

- determining the value of gas is more complicated. The value of gas in storage or in a production field today is a function of the expected value of gas in the future ("opportunity cost"). Historically gas markets have been based on continuous trading which allows traders to adjust their positions in the light of evolving current and future pricing information; and
- gas production and consumption needs only to be in balance over periods of hours or even days (as a result of the ability to store gas in the gas pipelines) rather than second by second. There is therefore no need for production and consumption plans to be determined a long time in advance. Indeed in some markets they can change without major consequence right up to the point of delivery.

We note that it is not therefore clear that simply implementing the auction process used in the electricity market would be the approach which is in the best interests of customers overall. This may be particularly relevant when there are continuous trading processes also used by the electricity market which could effectively facilitate cross border trade.

Timing and evolution

Finally, we make clear that to be of value in terms of ensuring competition and investment in the gas market, any target model must be designed with the potential future evolutions of the gas market in mind. And there are many such potential evolutions, from the future of indigenous production and shale gas through to the demand for gas in a decarbonised society.

Faced with such uncertainty, it is important that market forces are relied upon where possible, as experience indicates that they are more likely to adapt to future developments than administrative arrangements put in place by regulators. So whether it is avoiding unnecessary regulation of assets which can compete effectively in the wholesale market (such as storage or LNG terminals) or allowing the market to determine the details of traded markets (such as the development of arrangements for trading at hubs or on exchanges), avoiding the risk of unintended consequences of regulation should be at the forefront of the minds of policymakers and regulators.

Where regulation cannot be avoided, we note that implementation timescales must be realistic and futureproofing must be considered. The future nature of gas demand, and increasing demand volatility (as gas generation provides a back up to intermittent renewables) must be taken into account. And defining evolutionary arrangements which build on existing practice may carry less complexity and risk, and so result in a greater likelihood of earlier developments in the interests of customers than attempts at more revolutionary change.

1 Introduction

Following a 2007 sector inquiry findings highlighting the need for further progress in the European gas and electricity markets, the European Commission introduced a series of new regulatory arrangements across Europe, as part of its 3rd Energy Package.

The 3rd Energy Package requires the establishment of European Network Codes which will set the more detailed rules for various aspects of market and transmission arrangements, including for example the structure of network tariffs, arrangements for allocating network capacity, and balancing.

To develop a coherent overall framework for these Network Codes, the EC and the CEER have taken forward work to define a "target model" for gas markets in Europe (the "gas target model" or GTM). Frontier Economics, Ylios and Stratorg were commissioned to develop a proposal for a target model by GDF SUEZ, which:

- ensured the completion of an efficient internal market for natural gas and hence the resulting customer benefits; and
- ensured that the model was adapted to the current and potential future context and needs of the European gas market.

The vision for a target model for the European gas wholesale market needs to link to the legal requirements of the 3rd package legislation and the security of supply directive, and build on positions already set out by the Commission and regulators. In addition, the characteristics of the European gas market in Europe as well as current arrangements and the feasibility of transition towards a new system also need to be taken into account when defining a preferred GTM.

We therefore followed a three-staged approach to identifying a potential target model. We:

- developed a set of building blocks for a GTM, to identify the relevant scope of arrangements – we summarise these building blocks in chapter 2;
- defined of a set of criteria and objectives for the target model – we set out these criteria in chapter 3; and
- based on these criteria, developed a proposed design for each building block – we present our suggested target model design in terms of high level principles (as opposed to detailed design), along with accompanying rationale, in chapters 4, 5 and 6.

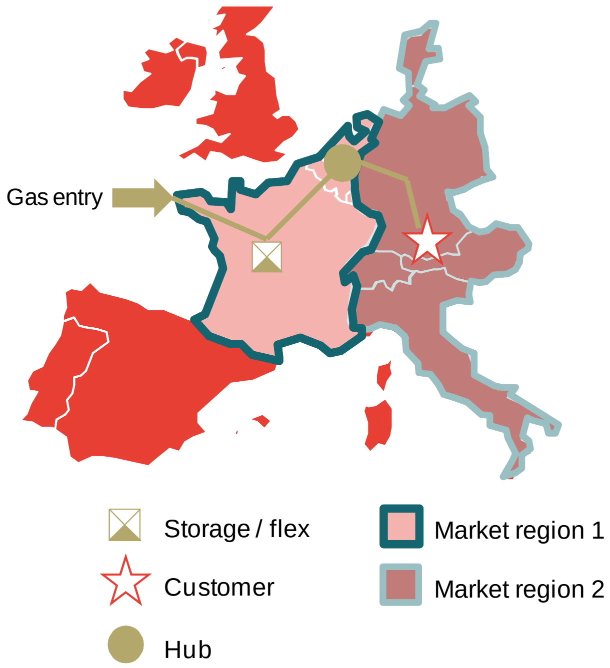
2 Scope of a target model

The scope of a gas target model is not necessarily clear. Therefore, to define the scope we have considered a generic transaction involving:

- the import of gas to a gas grid in the European Union;
- the transport of gas through an entry / exit region, potentially combined with further trading of gas in that region; and
- the supply of gas to a customer in a further entry / exit region.

Figure 1 illustrates such a transaction.

Figure 1. Stylised gas transaction



Source: Frontier Economics

This transaction would involve the following arrangements:

- access to the entry point and pipeline network in the first market region
- access to liquidity at a traded market point in the first region (and/or access to physical storage or other sources of flexibility in the first region);
- access to cross-border capacity between the two regions;
- access to the pipeline network in the second market region;

- effective balancing of the network in the second region to the extent that the customer's demand differed from the injections nominated into that region at the cross border point; and
- effective settlement arrangements to address the financial consequences of differences between aggregate injections and withdrawals.

From this transaction, we derived the following building blocks of a target gas market model:

Table 1. Building blocks

Building block		Definition
Region definition		• A definition of a region within which gas can freely flow once entry capacity has been secured
Entry / exit arrangements	**Access to entry capacity**	• Arrangements to ensure that participants can secure cost-reflective[1] and non-discriminatory access to inject gas at an entry point to the European gas network
	Within network capacity / exit capacity	• Within a market region, arrangements to ensure that participants have cost-reflective and non-discriminatory access to the high pressure network to transport gas from the entry point to a physical or virtual trading hub, and/or from a trading hub to an exit point (either to a customer site or to another region)
Access to cross-border capacity between regions		• Arrangements to ensure participants have cost-reflective and non-discriminatory access to capacity to flow gas from one market region to another
Access to liquidity/ flexibility		• Arrangements to ensure that participants have cost-reflective and non-discriminatory access to sources of liquidity and flexibility within a market region.
Network balancing		• Arrangements to ensure that, within a region, injections and offtakes are balanced across a reasonable period (to the extent required by pressure and flow constraints)
Settlement arrangements		• Arrangements guaranteeing that the price at which individual differences between injections, trades, injections / withdrawals from store, and offtakes are settled is non-discriminatory and cost-reflective

Source: Frontier Economics

We have not specifically considered aspects of market arrangements which are not related to a specific transaction, such as requirements for information

[1] Throughout, cost-reflective may be taken to imply a cost-reflective administratively calculated cost, or a cost based on market-based allocations.

disclosure, transparency etc. Equally, we have not dealt with detailed arrangements for specific situations (e.g. gas deficit emergencies) which are currently topical in a number of markets across Europe.

For each building block, we first defined the scope of possible options for gas target model. To do so, we considered:

- precedents from gas market arrangements in Europe;
- precedents from electricity, and specifically regarding the recent evolution in cross-border arrangements for electricity, towards implicit auctions and market coupling; and
- new potential solutions to fit to the specific objectives and circumstances of the European gas market.

For each building block, we then assessed these options against a range of criteria reflecting the legal objectives and constraints, a set of general principles, and market and regulatory evolutions.

Based on this assessment, we developed high level principles for the arrangements within a GTM. More work, both at the overall level and then in terms of translation of the model into national arrangements will be required prior to any implementation.

3 Criteria for assessment

In this chapter, we present the criteria that were used to assess options for each building block. These criteria include:

- compatibility with legal requirements set in the 3rd package regulation and the positions already set out by the Commission and regulators;
- consistency with the overall context of the European gas market; and
- consistency with current trends and the current path of evolution of the gas market.

We describe each in more detail below.

3.1 Legal requirements

The vision for a target model for the European gas wholesale market needs to be consistent with the legal requirements of the 3rd package legislation and security of supply directive. We provide a summary of the key aspects of these requirements in Table 2 below, by relevant building blocks.

Table 2. Requirements from EC 3rd package guidelines for internal gas market

Building block	Requirement
Region definition	• Tariffs for network users should be non-discriminatory and set separately for every entry point into or exit point out of the transmission system • The geographical area covered by each regional cooperation structure may be defined by the Commission, taking into account existing regional cooperation structures

Access to entry and exit capacity	• Tariffs should be cost-reflective
	• Tariffs or methodologies should
	  ▫ maintain or create interoperability
	  ▫ allow necessary investments to be carried out
	  ▫ give system operators appropriate short and long term incentives to increase efficiency, foster market integration and security of supply
	  ▫ be defined for short and long term and for firm and interruptible products (for interruptible, price should reflect interruption probability)
	• Tariffs can be determined through market-based arrangements
	• Capacity-allocation mechanisms and congestion-management procedures shall
	  ▫ facilitate the development of competition
	  ▫ provide economic signals for use of technical capacity and facilitate investment in new infrastructure

	◦ use primary and secondary markets to offer unused capacity
Access to cross-border capacity between regions	• In addition to network capacity allocation, arrangements shall ◦ promote the coordinated allocation of cross-border capacity ◦ enable an optimal management of the network ◦ promote joint gas exchanges • Tariffs should not distort trade across borders of different transmission systems • Long-term contracts shall not be prevented in so far as they comply with competition rules
Access to liquidity/ flexibility	• Capacity allocation mechanisms shall be compatible with market mechanisms including spot markets and trading hubs, while being flexible and capable of adapting to evolving market circumstances • Tariffs should not restrict market liquidity
Network balancing	• TSOs shall procure the energy they use for the carrying out of their functions according to market based procedures • Balancing services shall ◦ be performed in the most economic manner ◦ provide appropriate incentives for network users to balance their input and off-takes
Settlement arrangements	• Tariffs for balancing the network should be cost-reflective • Imbalance charges shall provide appropriate incentives on network users to balance their input and off-take of gas. They shall avoid cross-subsidisation between network users and shall not hamper the entry of new market entrants.

Source: Third Package legislation, Security of Supply directive

3.2 Overall market context

European regulators have started to develop a conceptual model for the European gas market, and have indicated that the overall goals of the model should include:

- cross-border integration into an efficient and effective market;
- efficient capacity allocation procedures, including market based mechanisms;
- efficient usage of pipeline capacity; and
- improving integration of trading points leading to a convergence of market prices.

Translating these objectives into specific assessment principles for each of the building blocks requires the overall context of the European gas market to be taken into account. For example, it is important that the model recognises a situation in which there are:

- countries in which large national market players exist;
- a range of existing contractual arrangements for commodity and capacity;
- distant supply sources;
- varying gas qualities;
- potential changes to the future use of gas (including related to developments in electricity); and
- physical network configurations based around historic usage patterns.

We have attempted to combined the overall objectives set out by the regulators above with the current context of the European gas market to develop some principles according to which the gas target model should be designed. We present these principles below, by building block.

3.2.1 Region definition

A region is an area within which gas, having paid entry, can be freely traded and then flow without constraint to any exit point. A very wide region definition implies that many potential sources of gas can compete with each other. However, it also carries with it the risk that the arrangements for access to capacity on the network will not accurately reflect the underlying physical capability.

The definition of a region should therefore be undertaken *on the basis of robust economic cost benefit analysis, taking into account all infrastructure (e.g. storage, LNG) in order to balance the benefits of competition with the congestion related costs (such as having to undertake uneconomic network investment to remove bottlenecks).*

3.2.2 Entry, exit and cross-border capacity

We have determined common principles for entry, exit and cross-border capacity.

First, *the European market should consist of market regions which are defined on a robust entry/exit basis*. In other words, within a geographic region, tariffs should be on an entry/exit basis, and movement of gas (once entry has been paid) within that region should be unrestricted, in order to facilitate the development of competition for the provision of wholesale gas.

Second, *network entry/exit capacity products should be defined which reflect the underlying physical characteristics of the network, the information available to the TSO (e.g. backhaul), and are not overly simplified (e.g. hub to hub).*

The model should be designed to minimise the transactions costs involved in trading gas in Europe. However, it is also important that the network capacity arrangements should send effective price signals in relation to the availability of transport capacity around Europe. Within a liberalised market, a key role of network capacity prices is to signal the attractiveness (from an overall system cost viewpoint) of incremental use of particular parts of the network.

Between regions, this means that network capacity products should reflect the underlying physical characteristics of the gas network, in order that price signals accurately reflect the presence or absence of scarcity of capacity. In determining the physical characteristics of the network it is important to note that available capacity can depend on other flows. For example, the available commercial network capacity for flow from country A to B depends on the planned flow from B to A. The higher the B to A flow, the higher the potential available commercial network capacity from A to B.

This means that where there is network congestion, separate capacity products are likely to be needed to send appropriate price signals. While simple network capacity products may be attractive to shippers, oversimplified products will result in price signals which do not reflect network characteristics and will result in decisions about entry and exit point location which result in sub-optimal use of network capacity and increase costs to European customers as a whole

The capacity arrangements must also *recognise that Europe is operating in a global market for gas, and hence needs to be attractive as a marketplace for gas (being attractive for suppliers to sell their gas, facilitating diversity of contracts).*

Gas market arrangements should facilitate purchase of gas by European customers on terms which will secure both efficient pricing and security of supply, as Europe is operating in a global market for gas. The model should not unduly constrain valid contracting options for shippers, as to do so could result in increased costs to customers.

Moreover, the definition of the model should ensure that shippers do not face significant basis risk between capacity and commodity positions that they are unable to manage, as this will also increase costs to customers.

The model should *facilitate long term contracts particularly for supply and for major new infrastructure investments* and should *promote infrastructure assets by avoiding regulatory arrangements which could result in stranded costs.*

The model should ensure that network infrastructure is attractive for potential investors, in order that the network can develop in an appropriate manner. This implies that tariffs which remunerate network investment should be calculated on the basis of an appropriate WACC and an efficient cost base, and that the capacity arrangements should result in an efficient allocation of risks with shippers.

Long term contracts for infrastructure, provided they do not foreclose market access, can be an important component of the model. They help to provide revenue certainty to investors and hence make infrastructure investment a potentially attractive proposition. Equally, from a customer viewpoint, they can help ensure that customers within a country do not end up funding the cost of underutilised assets built for international transit purposes (assuming bookings can be fixed in advance and pricing is set *ex ante*). They should therefore not be ruled out.

Where infrastructure assets are not supported by long term contracts, investors will require a clear and stable regulatory framework on which to base investment decisions. Absent long term contracts, the regulatory regime is the route through which investments will be remunerated. When investors make investment decisions on the basis of a specific regulatory regime, it is therefore important that they have a reasonable expectation that this regime will persist, or at least that changes to it will be both transparent and objectively determined in relation to a clear and stable set of criteria. Otherwise the cost of capital demanded for all infrastructure investments will increase, to the cost of European customers.

In particular, the position of investors in relation to stranded costs must be both clear at the time investors make a decision and must not be changed opportunistically after investments have been made. Investors may decide to bear all or part of the risk of asset utilisation on making investments. However, having made a decision, changing the approach could result in investors being worse off. If investors believe this is a risk, they will increase the overall reward required to make the investment in the first place. This higher reward will have to be paid for by European customers.

3.2.3 Access to liquidity and flexibility

A range of assets can provide flexibility to the market. These include storage and LNG import terminals, but also include production fields and imported gas. The gas target model should *avoid over-regulation of assets which compete in the wholesale market.*

Regulation is less effective than competition at setting efficient prices. In particular, "regulatory failure" (setting the wrong prices either from the perspective of sending price signals or remunerating investment) is an important risk in any regulatory regime.

Where possible (i.e. where the market structures allow competition and where existing regulatory arrangements allow a level playing field) assets which compete with other sources of gas in the wholesale market should be subject to "light touch" regulation which allows their prices to be set through the competitive market. This approach should minimise the risk of regulatory failure.

3.2.4 Balancing and settlement arrangements

Arrangements for balancing must *allow the TSO to ensure the security of the network at the most efficient cost*. The detailed nature of arrangements is likely to vary by system.

Arrangements for settlement must *ensure that all shippers are on a level playing field, send cost reflective price signals in relation to the need to balance within a portfolio over the relevant time period, and not create artificial barriers to entry to the market by excessive requirements to balance injections and withdrawals.*

3.3 Current trends and market evolution

Our final criteria for the definition of the gas market model is consistency with current market trends. We studied a number of European markets with a view to drawing out such general trends. Table 3 presents our findings.

Table 3. European trends in gas market arrangements

Buidling blocks	Trends
Region definition	• Trend towards one geographic region per country, as is the case in the United Kingdom and the Netherlands, and the trend in France and Germany • Trend towards the end of the distinction between gas qualities for traders (network operator responsible for swaps and quality conversions, in the Netherlands and Germany)
Capacity related building blocks • Access to entry capacity • Within region network access & incentives • Access to cross-border capacity between regions	• Trend towards auctions (e.g. in Great Britain, for short term capacity in France, or for new capacity in Germany) as an alternative to first come, first served capacity allocation • Both long term and short term capacity booking, sometimes with limits on the amount of capacity available long term (GB 90%, France 80%) • Interruptible products for uncertain capacity (e.g. backhaul) and UIOLI • Open seasons to determine the need for new investments • Secondary markets for both firm and interruptible capacity • Regulatory approval for new investment needed for all but exempt infrastructure – recovery assured by regulatory regime • Trend towards rTPA exemptions for new cross-border capacity • Some exchanges combining capacity and commodity trading • Rules at cross-border points typically similar to those at entry points

Access to liquidity / flexibility	• Access to linepack typically reflected through imbalance tolerance levels • Use of flexibility from neighbouring countries (e.g. at the Dutch-German border) • Market led development of virtual trading points
Balancing	• Some continuing use of contracts to buy/sell balancing gas, but some trend towards balancing market platforms
Settlement arrangements	• No converging trend regarding tolerance level, or hourly or daily balancing period • Trend towards use of balancing market for pricing

Source: Frontier Economics

4 Region size

The first building block we consider is the definition of regions. These are defined as market areas: once a market participant has gas in a market region (i.e. has acquired and nominated use of entry capacity), that gas can be moved to any other location in the region without acquisition of further capacity. Similarly, if a participant offers gas for sale at an entry point at a given region, any other participant can purchase that gas and have it contractually delivered to any exit point within that region without further individual network access transactions.

This chapter sets out the proposed approach to defining regions at a high level and then describes the approach in more detail.

4.1 Preferred model for region definition

The definition of geographic region size will have real impacts in terms of costs and benefits. Increasing region size will:

- create short term transfers between shippers and customers, and may also cause longer term costs resulting from inefficient siting of injections and withdrawals; and
- create benefits in terms of increased competition and lower transactions costs.

There is therefore a strong rationale for region size to be determined in the light of clearly presented cost-benefit analysis, rather than starting from any presumption (for example, that larger regions are by definition "good"[2]). This will avoid changes in region definition which result in higher costs to European customers.

Below we consider the way in which costs and benefits could be considered in such an analysis.

4.2 Costs

To demonstrate how the potential costs of merging two regions could be analysed, we use a stylised case study. We consider two neighbouring regions (say, North and South), and assume, to begin, perfect competition in each region. Assume now that

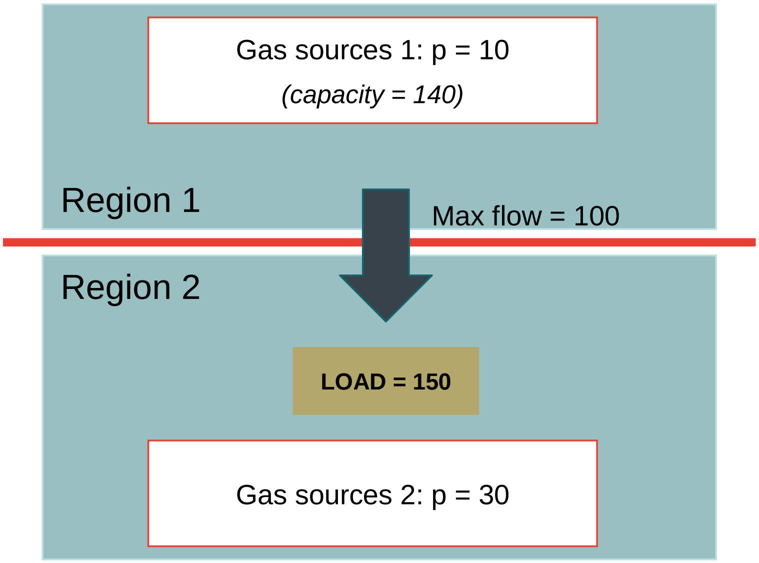
- the gas price in the North is lower than in the South;

2 Or that "the value of a functioning market is higher than the cost of achieving it".

- the cross-border capacity between the North and the South is lower than the total load in the South, and lower than the total capacity in the North.

This example is illustrated in Figure 2

Figure 2. Stylised example of region definition



Source: Frontier Economics

In this stylised example, **in the counterfactual, with two zones,** the TSOs will allocate rights on the inter-region boundary equal to the available cross-border capacity (100 in this example).

Assume that these two regions are merged. **In a single region**, gas can flow anywhere once the entry charge is paid.

- In that case, demand in the South is likely to contract as much volume as it can with the cheaper gas source in the North (i.e. in the stylised example, up to the 140 capacity of the North).
- Because in this example the cross border pipeline capacity is lower than both demand in the South and supply in the North, it will be congested.
- The TSO will need to "sell back" the gas to sources in the North (or buy back their entry capacity) and buy gas from sources in the South in order to balance the network

- This transaction will be loss making (buy high, sell low) and the congestion management cost will need to be recovered from customers (e.g. through network tariffs).

This stylised case study highlights the main risk with merging two regions: increasing congestion management costs[3]. Congestion in turn would result in two types of costs:

- short term transfers (higher cost to customers) and
- a long term economic cost.

Short term transfers (higher cost to customers)

Assuming that demand is insensitive to price, production and consumption should be the same with one or two zones. In consequence the change in region definition would imply no immediate change in economic welfare.

However, compared to the two zone situation, with a single zone, there will be transfers between customers and producers. In our stylised example, following the merger:

- customers in the south will pay less for their gas;
- producers in the north will receive more;
- customers in the north will pay more (though there are none shown in our stylised example);
- producers in the south will receive the same[4]; and
- as more entry rights have been allocated than the network can accommodate, the TSO (and therefore customers as a whole) compensates producers in the north for not being able to secure access.

In aggregate, customers are likely to have paid more than before the merger. Moreover, if we relax the assumption that demand is insensitive to price, there would additionally be economic welfare considerations to take into account (although these are likely to be smaller in magnitude).

Finally, if we relax the assumption of perfect competition, there is a risk that the TSO (as a distressed buyer) has to pay higher levels of compensation to the

[3] There are likely to be other costs associated with merging regions, not least those associated with regulatory and political decision making and (where relevant) harmonisation of existing commercial, legal and regulatory arrangements across jurisdictions.

[4] In fact, if producers in the south are requested to sell gas to the TSO in the very short term, they may perceive them as a distressed purchaser and may therefore command a greater payment than they would otherwise have received.

producers in the north for lack of network access than they would under a competitive market, resulting in even higher costs to customers.

Long term economic cost

In the longer run, the merger of these two regions could create distorting incentives in the connection decision of new sources (both producers / import sources and customers). Indeed, in our stylised example

- **In the counterfactual, with two zones**, new sources who would like to connect will internalise the limited cross-border capacity and the risk of congestion in their decision to invest in the North or in the South

- **In the single zone case,** there is the potential for new suppliers to connect in the North to serve load in the South without any additional cost. If connecting in the North therefore becomes a cheaper route for the suppliers, they will do this irrespective of cost to the system. The same reasoning applies to customers.

These inefficient siting decisions will increase overall system costs (for example, as a result of increased demand for network investment) and so will constitute a welfare loss.

4.3 Benefits

Our previous stylised example assumed perfect competition. Here we relax this assumption. The two main welfare increases that would result from merging various regions would be an increase in competition and a likely reduction in transaction costs.

More competition

Assume now that there is abuse of market power in the import constrained zone. In this case, merging the regions would increase the level of competition and may mitigate the abuse. This would result in an economic benefit to customers in that region (lower prices for more gas).

With or without abuse of dominant position, merging the two market zones is likely to imply more competitors on the wider market, which should lead to deeper and more liquid wholesale markets (both spot and forward). The direct consequence of this may be better forward price signals and more informed long term decisions, again with a potential gain in economic welfare.

These two benefits from wider regions could be non-negligible. We note that they are potentially more difficult to estimate than the costs described above, as:

- the impact of more competition on prices and longer term investment decisions will depend on individual behaviours;
- the impact of improved price signals on longer term decisions is difficult to model.

However, this does not mean an attempt should not be made at estimating these benefits prior to considering any increase in region size. At the very least, the credibility of the size of benefit required to offset cost increases should be considered.

Lower transaction costs

Even with two perfectly competitive markets, there may be transactions costs in a multi-region solution. In our stylised example, assuming an outside shipper needs to flow gas through the North region to deliver gas in the South, it would have to go through the processes of reserving entry and exit capacity in the North, cross-border capacity and entry and exit capacity in the south.

Participation in these capacity allocation processes has a transaction cost that would be reduced should the two zones be merged: in this case the same shipper would only have to go through the entry and exit allocation process of the single zone.

The reduction in these transaction costs creates an economic benefit, and a welfare increase.

4.4 Quality regions

The above discussion was presented in terms of network capacity constraints. However, a similar analytical framework can be applied to gas quality constraints, i.e. to assess whether there would be benefits in different qualities of gas being treated as one commodity by the shippers.

Currently, gas regions respect significant quality differences, and shippers book quality conversion capacity if they wish to flow gas between quality regions.

In a system where quality regions were merged, shippers would be able to inject and withdraw gas of different qualities anywhere within the entry and exit region. The system operator would manage the overall quality of the system to ensure that gas quality at exit points remained within acceptable tolerances. Therefore, compared to the counterfactual, in a single gas quality market:

- Costs of conversion would be internalised and socialised by the TSO, therefore creating short-term transfers, and potentially distorting incentives for shippers in their decision to use different qualities of gas; and

- Shippers previously supplying one gas quality would then compete with shippers supplying the other quality, increasing competition and leading to benefits. Additionally, transaction costs would decrease as the shippers would not need to book quality conversion capacity.

These costs and benefits are similar in nature to those described above in relation to regions and capacity constraints. The same cost benefit framework should be capable of application to both aspects of region definition.

5 Access to capacity

In this chapter consider those aspects of a potential gas target model in relation to the making available of transmission capacity both to facilitate access within systems and to integrate systems across Europe. This can be considered in two dimensions:

- the capacity which is to be made available, where we consider entry and cross border capacity on one hand and exit capacity on the other; and
- the timing of making capacity available, where drawing on precedent from the electricity market, we distinguish between forward markets and short term markets

We therefore consider separately:

- forward entry and cross-border capacity;
- forward and short term exit capacity; and
- short term cross-border capacity.

5.1 Entry + cross-border forward capacity

We consider two aspects to forward entry and cross-border capacity:

- the definition of the capacity product; and
- the process by which it is made available.

5.1.1 Definition of capacity product

The entry and cross-border forward capacity product must specify where, in what volumes, and for how long capacity is sold by the TSO to shippers.

Location

The definition of the location of entry or cross-border capacity is likely to be less contentious than the other elements. The key issue is likely to relate to bundling of individual locations (e.g. sale of a single capacity product across multiple physically distinct entry or cross-border locations).

There is a potential benefit in bundling capacity products to the extent it reduces transactions complexity for shippers and potentially increases the depth of secondary capacity markets. However, it is important that any bundling ensures that entry and cross-border products remain capable of being cost reflective and that they provide the TSO with effective tools for the management of the system. This implies that products should only be bundled if the physical routes are genuinely substitutes for the vast majority of the time from the TSO's viewpoint.

Put another way, they should only be bundled if the TSO would treat gas flows from the physically distinct locations in an identical manner from the point of view of ensuring system integrity.

Volume

There are a number of potential measures of the volume of any entry or cross-border point. These include:

- the maximum physical capacity of the point itself, which considers purely the physical infrastructure at the point and ignores considerations relating to the deep system;
- the maximum physical capacity of the point and the deeper network, which considers the entire system(s) to which the point is connected, but measures the capacity under the most advantageous supply and demand flow scenarios; and
- the expected physical capacity of the point and the deeper network, which considers the most likely supply and demand flow scenarios on the wider system(s) and the associated volume which could be accommodated through the point in question.

There may be a concern on the part of regulators that TSOs will be unduly conservative in their assessment of likely volumes available. This concern may relate to the perception that TSOs would prefer to release incremental capacity as it becomes clear that it will be available, rather than risk scaling back or buying back capacity from shippers having sold more capacity forward.

In a perfect market and with perfect information, and if TSOs are required to buy back capacity from shippers, the volume released should not matter. Even if the TSO releases much more capacity than will in reality be available, shippers would be able to predict that the TSO will have to buy back the capacity and will therefore perceive its efficient value.

However, such conditions are unlikely to prevail. Overselling capacity carries the risk of the achieved price being low, and there being a transfer from the TSO (and hence customers) to shippers. It is therefore likely to be preferable for TSOs to release the expected level of capacity available (given supply and demand scenarios) and for there to be regulatory oversight (or a regulatory incentive) to ensure that the TSO makes all reasonable capacity available given the information they hold at any point in time.

As the information available to the TSO on the likely pattern of flows on the network increases or becomes more certain towards real time, the volume of capacity made available may increase.

In the interim, to the extent that there is demand among shippers, there is a rationale to the TSO releasing interruptible capacity where it believes there may (under some but not all credible flow scenarios) be available capacity. Provided the price of interruptible capacity is set to reflect the probability of interruption, the issue of such longer term interruptible capacity should not "undermine" the firm product. Further, it places the risk associated with changes in flow scenarios with shippers who may (as a result of their market knowledge) be reasonably well placed to manage it.

Use it or lose it (UIOLI)

UIOLI arrangements typically aim to prevent the ability of incumbent shippers to hold but not use network capacity, and in so doing foreclose market access to other shippers. UIOLI conditions can be implemented over different timeframes:

- long term UIOLI arrangements may be designed to remove forward capacity from shippers, for example if shippers have not used the capacity over a period of time; and
- short term UIOLI arrangements may be designed to remove capacity from shippers close to the time of delivery if they are not expected to use it, while allowing them to retain long term rights.

In relation to forward capacity, UIOLI arrangements may not be beneficial. Rules which constrain[5] the ability of shippers to determine their capacity utilisation may distort the gas market in a way which is against the interest of customers:

- there is a risk that rules around minimum utilisation distort the operation of the commodity market and result in gas from more expensive sources flowing in order to meet essentially arbitrary utilisation rules – this would increase the overall cost of meeting gas demand; and
- the ability of shippers to hold on to capacity to provide an option to utilise their overall portfolio may be valued by shippers even within the context of a competitive market, and its removal could reduce the value of forward capacity[6];

Further, if there are effective short term UIOLI arrangements in place which do not suffer from such problems, it is not clear that longer term UIOLI arrangements will significantly reduce the risk of market foreclosure. It is likely to be preferable for attention in relation to UIOLI arrangements to focus on the

5 By incentivising its use with the threat of loss.

6 There may also be legal issues with the removal of this option.

short term, and for longer term UIOLI arrangements to be avoided in any target model. We return to the issue of short term UIOLI arrangements below.

Duration

In determining capacity product duration, two competing objectives must be balanced:

- from an efficiency perspective, volume should be allocated in a way which maximises its value to the TSO (and therefore to customers); and
- from a competition perspective, there may be concerns about allocating significant volume to longer term contracts as it may allow incumbent operators to foreclose access to competitors.

Given the current context of gas commodity markets, it is likely that these two objectives will conflict somewhat. Gas tends to be bought and sold through longer term contracts, and there is therefore likely to be demand for capacity to be made available on similar durations (otherwise shippers will face a basis risk between their commodity and capacity positions).

However, if there are effective UIOLI conditions in place the competition concerns should be reduced. In this situation it would seem appropriate for available capacity to be offered to the market on a relatively long term basis – perhaps 10-15 years. We note that entry capacity is already sold long term in the GB market, and the Project Co-ordination Group Target Model for forward trading in electricity suggests a similar approach (with forward capacity contracts being matched in duration to those in the commodity market, albeit that commodity contracts are shorter in the electricity market) [7].

From the long term (e.g. 10-15 years) to the short term (e.g. just before day ahead, when the proposed short term arrangements presented below would commence), following the same principle, capacity could be allocated to contracts in proportion to market demand resulting from commodity contract volumes.

7 The 15th Florence Forum, held 24-25 November 2008, invited ERGEG to establish a Project Coordination Group of experts, with participants from EC, Regulators, ETSO, Europex, Eurelectric and EFET, involving Member States' representatives as appropriate, with the tasks of developing a practical and achievable model to harmonise interregional and then EU-wide coordinated congestion management, and of proposing a roadmap with concrete measures and a detailed timeframe, taking into account progress achieved in the ERGEG ERI. This Project Coordination Group (PCG) is chaired by the European Energy Regulators and has been meeting regularly to develop an EU-wide target model for the integration of the regional electricity markets. The target model covers forward, day-ahead, intraday and balancing markets as well as capacity calculation and governance issues.

5.1.2 Process for making capacity available

In relation to the process for making capacity available, we distinguish between:

- new capacity; and
- existing capacity.

New capacity

There is an economic rationale for the use of auctions (or any other market based allocation process) to sell long term capacity, as this should ensure that capacity is allocated to those who value it the most. An auction or market based process for the sale of forward capacity could be considered as a structured evolution of current open season arrangements.

A reserve price could be set to ensure that new capacity is only built if the value of the capacity (as expressed through shippers' bids in the auction) is greater than the cost of building the capacity[8] (in other words, if the net present value from the sale of capacity in the auction is greater than the expected cost of building the capacity). The precise design of such reserve prices would need careful consideration given the potential for significant differences between the average and marginal costs of new capacity over different volumes.

The auction revenue resulting from capacity sales should contribute to the allowed revenue of the respective TSOs – in other words, it should be used to offset network charges paid by national customers. For cross border capacity, a rule will be required for sharing the auction revenue between the two relevant TSOs.

Such auction arrangements will help to ensure that the funding of significant new capacity is underwritten by the shippers who express the demand for it. From a customer perspective, this is preferable to the alternative where shippers are not required to make long term financial commitments at a market determined price, and where there is therefore a risk that costs associated with new capacity in the case of underutilisation is born by end customers in the country in which the pipeline assets are located.

Existing capacity

Where there is the potential for excess demand (i.e. contractual congestion) there is also a rationale to using auctions to offer existing capacity to the market. Auction prices (and prices in secondary markets) will provide signals to shippers as to the scarcity (or otherwise) of different capacity products, and therefore

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8 Alternatively, if existing "economic test" arrangements are in place, these could continue to be applied.

provide information as to the gas transport routes which would best utilise the gas transmission system.

However, in order to ensure that investors continue to have a positive outlook on the overall regime, it is important that such auctions are only for available capacity (i.e. that which has not already been contracted). Existing long term capacity rights should be respected, otherwise it is likely that investors will seek risk premia related to the risk of expropriation of contractual rights.

The auction timings should be consistent with the contract durations defined, in other words from the long term through to day ahead.

There is a rationale for the auction processes having a reserve price in order to:

- **guard against the exercise of market power**: if there are too few potential purchasers of a particular product, they will be able to exert market power in the auction and secure the capacity at lower than a competitive price. In this case, a reserve price may be required to estimate the outcome of a competitive market for capacity, or alternatively to estimate the long run marginal cost of capacity (which should represent the average outcome of a series of competitive processes over time); and
- **incentivise longer term bookings**: longer term bookings can provide valuable information for TSOs in relation to the likely evolution of demand for capacity on the network (relative, for example to a situation where all capacity is simply booked day ahead). Given this, there may be a benefit to reserve prices which incentivise parties to book capacity longer term to maximise the information available to the TSO.

However, the determination of reserve prices needs to be carefully considered. In particular, reserve prices should not be set at a level which prevents the clearing of competitive auction processes (in other words, set at a level above the market clearing price), as this would result in the underutilisation of available capacity.

As with auctions for new capacity, the auction revenue resulting from capacity sales should contribute to the allowed revenue of the respective TSOs – in other words, it should be used to offset network charges paid by national customers. For cross border capacity, a rule will be required for sharing the auction revenue between the two relevant TSOs.

5.2 Exit tariffs (forward & short term)

Auction processes for entry and cross-border capacity products cannot be guaranteed to recover TSO allowed revenue. For example, if there were little or no congestion in relation to a particular system, the revenue from competitive auctions processes would be low or even zero.

However, to secure an attractive investment climate, TSOs must be allowed to recover the allowed revenue agreed with their regulatory authorities. As we note above, market based arrangements for entry and cross-border access ensures that prices send signals to shippers as to the best transmission routes to use. Recovery of additional revenue from these products would therefore risk distorting shipper behaviour.

Instead, there is a logic to recovering the residual revenue from exit tariffs. The demand for exit capacity is not insensitive to price, because as price goes up it is likely that demand will fall (more so for industrial rather than domestic gas use). However, in general it is potentially less sensitive to price than demand for entry or cross border products (given that there are typically a range of routes which shippers can use to transport gas around Europe and a range of different potential gas sources). Economic theory would therefore suggest that recovering residual revenue from exit tariffs is preferable, as it is less likely to distort behaviour.

This would imply that the level of exit tariffs should be set to recover the relevant TSO's allowed revenue *less* any contributions from the sale of entry or cross border capacity. Given the relatively infrequent occurrence of competition between users for any given exit capacity product, the allocation of exit capacity priced to recover this residual revenue could then be on a first come first served bookings basis.

It should be acknowledged that this approach will result in an increase in exit tariff volatility, as exit tariffs will be low in periods of high congestion and high in periods of low congestion. While there is little that can be done to avoid such volatility under this regime, TSOs could be required to provide tariff forecasts to shippers in order to give them the maximum information possible prior to striking contracts with their customers. Shippers may also seek to change the form of contracts with end customers to allow for the passthrough of changes in exit tariff charges over time.

There are two clear exceptions to the general assumption that the demand for exit capacity is less sensitive to price, namely exit capacity for storage sites and for cross-border points. We consider an appropriate approach to each of these in turn.

Storage sites

The utilisation of gas storage facilities is driven by intertemporal price spreads. For long range storage, the key spread might be between summer and winter gas prices. For medium range storage, the relevant spread might be between weekday and weekend prices, or between warmer and colder winter days. If the spread between prices narrows, the storage site will tend to be used less (as the profit from storing gas for later use is lower).

If storage sites face an exit charge from the gas transmission system, the total cost of injecting gas into the storage site for later sale to the market will be higher. Therefore, for a given spread between wholesale prices, the effective spread (as seen by the storage capacity holder who has to pay transmission charges) will be lower.

Therefore, if the transmission charge relates to the recovery of TSO allowed revenue (as opposed to one which reflects the marginal cost of capacity for the storage site), other things being equal there is a risk that there is underutilisation of the storage asset (relative to an efficient level).

Put another way, while final demand may be assumed to be relatively insensitive to price, the same is not true of exit demand related to storage injection. On the contrary, the level of storage injection is a direct function of price (or, at least of the difference between two prices).

Therefore, there is a rationale for storage sites to be exempted from exit charges to the extent that they do not reflect the local forward looking marginal cost of capacity on the network.

Cross-border exit points

The case of cross-border exit points is more complex.

The demand for cross border exit capacity can also be argued to be relatively sensitive to price, in just the same was as cross-border capacity itself is price sensitive. As we note above, this is because there are typically multiple different routes by which gas can be transported through Europe and a range of potential gas sources. An increase in the price of transport on a given route might result in volumes switching to another route or to another gas source.

By this logic, placing an exit charge on cross-border flows might be considered inappropriate, as it would risk distorting behaviour. For example, in a competitive market, an exit charge to recover TSO allowed revenue may discourage flow across an uncongested border and move flow to a more congested route or result in use of a more expensive gas source. This would result in sub-optimal utilisation of the European pipeline infrastructure and higher costs to customers. Equally, it is not clear that it would meet the requirements of Regulation 715/2009, which include that:

> *"Tariffs for network access shall neither restrict market liquidity nor distort trade across borders of different transmission systems"* (Art 13(2))

However the alternative approach (exempting cross border flows from exit charges, as is the case in the electricity market) could be considered equally undesirable. This is because this could result in significant costs being borne by the national customers of one country for the benefit of gas customers in another.

Consider the simple example of a source of gas supply which enters the network in country A and is transported through the network to serve gas demand in country B. Further, assume that there has been sufficient investment in country A to ensure that there is no congestion between the source of supply in country A and the gas demand in country B.

The absence of congestion at the border between country A and country B implies that there should be no revenue from the auction of cross-border capacity. Assuming (for simplicity) that the entry point was also uncongested, this implies that there is no contribution to the revenue of the TSO in country A from this transit flow of gas.

However, the cost of investment in the network to facilitate this flow has to be recovered. If there is no exit charge on the cross-border flow of gas, the entire of this revenue recovery is from national customers in country A. In other words, customers in country A have to pay for network investments which facilitate demand being served in country B and are of little or no value from a domestic perspective.

This is clearly not an equitable situation. This problem exists in the electricity market[9]. However, it is arguably even more significant in the gas market given the much greater proportion of gas flows which transit national systems.

The ideal solution to this problem would be an arrangement by which the TSO in country B compensates the TSO in country A for use of the network. In this way, users in country B who pay exit charges would pay for the network investments in country A. However such a solution is likely, from a political perspective, to be a long way off.

In the absence of such compensation arrangements, and given the proportion of European gas demand which is met through cross-border flows, the "least worst" option may be charge tariffs to contribute towards TSO cost recovery on cross-border exit points.

5.3 Cross-border short term integration

The final aspect to arrangements for access to capacity relates to short term integration of systems (analogous to arrangements for market coupling in the electricity market).

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9 See for example http://ec.europa.eu/energy/gas_electricity/studies/doc/electricity/2008_rpt_eu_transmission_incentives.pdf

There are a number of aspects to these short term arrangements which are important in relation to the overall objectives of the target model. As for forward capacity, these include:

- determination of the volume of capacity available (which includes definition of capacity renomination rights and short term UIOLI arrangements);
- the duration of capacity; and
- the process for allocating capacity.

We consider each in turn below.

5.3.1 Determination of the volume of short term capacity available

As discussed in relation to forward capacity above, and as embodied in a number of the arrangements for market coupling in the European electricity system, the volume of short term cross-border capacity available needs to take into account:

- the expected capacity of the transmission system; and
- the capacity rights already issued to shippers which are expected to be used.

All capacity which the TSO believes is likely to be physically available but which is not likely to be used under existing contracts should be made available to the market in the short term in order to maximise efficient use of the network.

The capacity available to be sold on a firm basis is likely to comprise:

- capacity not sold in previous auctions (i.e. which was offered to the market but which did not sell); and
- capacity which is only now believed to available by the TSO as a result of increased flow scenario certainty day ahead (i.e. backhaul capacity where there was previously insufficient certainty as to the likelihood of the forward flow).

The arrangements to determine the volume of capacity made available in the short term must also (for the reasons discussed above in relation to preventing the foreclosure of access to markets) include UIOLI arrangements. In the electricity market, this is achieved by also making available in the short term capacity which has been sold but which shippers declare they will not use. If users do not nominate the use of capacity, it is released to the market in order to prevent them from being able to hoard it when others would have used it efficiently.

However, in the electricity market, the need to balance demand and supply continuously means TSOs need to freeze nomination schedules of participants earlier, and hence cannot accommodate the possibility of ongoing participant renomination. This contrasts with the gas market, where there have traditionally been arrangements by which shippers can renominate gas flows near real time and even during the delivery day[10]. There is a rationale to renomination rights continuing to as near the time of final delivery of gas during the day as physical possible while preserving system security. This is because renomination facilitates shipper balancing of supply and demand.

As the time of delivery nears and more information is available on both demand and the economic conditions of available supply sources, shippers can re-optimise their purchases through their portfolio of gas contracts and then renominate their flows in order to ensure they are serving demand as efficiently as possible. For example, if shippers realise that gas procured through one set of contracts will actually be more economically attractive than that through another, then can renominate flows (buying more from one set of contracts and less from another).

In contrast, if shipper renomination is frozen (e.g. at the day ahead stage), gas flows could only change as a result of TSO action. Therefore the optimisation could only by undertaken by TSOs, for example by:

- the TSO buying gas at one entry or cross border point (representing incremental gas under one set of purchase contracts) and selling gas at another (representing a reduction in gas procured under a second set of contracts);
- the TSO negotiating with neighbouring TSOs to secure a greater flow of gas across their system and then buying this gas at a cross border point and selling gas at another point where the gas was more expensive.

This approach is potentially undesirable from a number of perspectives:

- TSOs are likely to be less effective traders and portfolio optimisers than shippers, since it is not their core business activity – their personnel will not be trained to act as traders, and their analytical tools will not necessarily be suited to a trading activity;
- the short term offers to buy and sell gas made by shippers to TSOs may command a discount and premium respectively to reflect the short term nature of the potential transaction; and

10 This contrasts with electricity where the need to balance demand and supply continuously means TSOs need to freeze nomination schedules of participants earlier, and hence cannot accommodate the possibility of ongoing participant renomination.

- TSOs are national in outlook, whereas shippers will take a consolidated view over their (international) portfolio. For TSOs to secure gas from sources outside their territories may require them to interact with other TSOs which will increase transactions costs and co-ordination requirements, and reduce the likelihood of an effective optimisation of potential sources of supply on an international basis. Given the extent to which gas is sourced internationally, this could represent a significant reduction in efficiency[11].

Equally, where capacity is sold at auction, reducing renomination rights will reduce the optionality associated with capacity contracts and hence reduce its value to shippers. This could feed through to higher (exit) tariffs for national customers.

Therefore, from the perspective of ensuring that customers pay the lowest price possible for their gas supply, it is arguably desirable that shippers retain their ability to renominate gas flows[12]. However, this means that the approach taken to short term UIOLI in the electricity market will be less effective in the gas market, because if they are able to renominate, declaring that they will not use capacity would be equivalent to shippers turning down a free option (which will always have a positive value).

This is not to say that there is no merit in implementing a process whereby shippers can declare that they will not use certain capacity, but rather that additional complementary UIOLI arrangements are likely to be required.

The most effective may be the issue of interruptible capacity by the TSO where it believes that shippers are unlikely to use their capacity. This allows the TSO to ensure that the original shipper holding the firm right cannot hoard the capacity (as were it to try to do so, other shippers could flow gas using the interruptible product). However, it preserves the ability of shippers to renominate under their long term contracts near to real time and hence reduces the risk that efficient sources of gas are not brought to market.

Additionally, it has the advantages that it cannot be argued to amount to expropriation of existing contractual rights, and that it places utilisation risk back with shippers who, as a result of their proximity to the market, may be well placed to manage it.

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11 In extremis, it could result in gas being withdrawn from national storage facilities instead of from international purchase contracts, reducing national security of supply.

12 Up to the point at which the TSO requires renomination to cease in order to be able to guarantee the overall balance of the system – this timing is likely to vary according to national system characteristics.

5.3.2 Duration of capacity

The interpretation of "short term" is a matter for judgement. However, given the convergence between the two sectors, there may be a rationale to using the same definition in the gas market as is used in electricity, namely day ahead[13]. This would imply the release of firm and interruptible capacity at the day ahead stage for the coming gas day.

5.3.3 Process for allocating capacity

The process for allocating short term capacity in the electricity market is typically some form of implicit auctioning (e.g. market splitting in the Nordic area, market coupling in the CWE area). This involves the design of a single auction process through which capacity and commodity are traded, with an algorithm determining the most efficient use of available (firm) capacity.

In contrast to the electricity sector, there is no history of short term commodity auctions in gas. In part, this may be because gas costs and volumetric availabilities are less well defined at any given point in time than is the case in electricity. Gas typically has a very low short run marginal cost of supply, and valuations are driven more by opportunity cost considerations. Equally, as we note above, from a system perspective there is less requirement to force nominations for flow at a given point in time to provide information to the TSO to facilitate balancing. In contrast to electricity, the gas system can cope with differences in aggregate supply and demand over minutes or even hours, and hence in some markets, renomination can continue through the gas day.

In contrast, there is significant experience with continuous trading of gas commodity. There may therefore be a rationale to considering whether effective utilisation of the gas transmission network can be achieved through integration of continuously traded markets rather than through the implementation of auctions. This would be a more evolutionary option, and may therefore also turn out to have lower implementation costs. It may also create fewer problems in terms of gas/electricity integration. Gas is a major fuel source for electricity today and is expected to continue to be so going forward. Single shot auction processes in both electricity and gas would create inevitable co-ordination issues[14]:

- if the electricity auction was first, a gas generator would not have a clear view of likely gas prices with which to formulate bids; and

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13 We note that in the broader context, gas timescales are typically longer than those in electricity, and that therefore in other contexts what is considered "short term" in the gas market may be considered as medium or longer term for electricity.

14 The interaction between gas contracts and electricity auctions were a significant issue in relation to the harmonisation of electricity auction times across the CWE area.

- if the gas auction was first, a gas generator would have to guess the extent of any incremental electricity sales in the subsequent electricity auction, and may then find out they either have a surplus of deficit of gas in reality.

Finally, and given the above discussion on the benefits of retaining renomination rights, it would allow the TSO to take an evolutionary view to firm capacity availability in the light of updating flow information during the day, rather than requiring a single shot volume determination for the purposes of a specific auction.

There is already experience of a model of market integration and making capacity available using continuously traded commodity markets from the electricity market. The Elbas market in the Nordic area commences operation after the day ahead auction and ensures that residual capacity is made available to the market efficiently, while minimising transactions costs and basis risk for shippers by bundling capacity and commodity transactions.

Those with electricity to bid or offer in one region place their trades onto the Elbas continuously traded market. These trades are visible to all other participants within that region. They are also visible to participants outside the region *provided* there is sufficient transmission capacity to allow the energy to be bought or sold. For example, an offer to sell electricity would only be visible to participants in other regions to which there was available export capacity.

This approach is also consistent with the proposed PCG Target Model treatment of intraday trading in electricity.

A similar approach could be adopted for cross-border short term gas markets (indeed, a trial of arrangements similar to this is planned between the PEG Nord and PEG Sud regions in France). To minimise transactions costs further, it would also be possible for exchanges to administer the arrangements for exit tariffs on the exporting system at the time any transaction was concluded.

Such arrangements would avoid the need for shippers to conclude separate capacity and commodity products and should support the integration of markets (and hence the efficient use of transmission capacity). While capacity allocation would technically be "first come first served" in nature, it would be automatically linked to completed exchange-based anonymous commodity transactions, and in that sense, market based.

It is important to note that no revenue from congestion rent would accrue to the TSOs in relation to short term capacity under this approach. However, to the extent that this capacity represents a relatively small residual after the forward capacity allocation process, this may not be considered a significant problem.

6 Liquidity, flexibility, balancing and settlement

In this chapter, we turn to some key aspects of the arrangements for traded markets, the provision of flexibility and balancing. We consider in turn arrangements:

- for shippers to secure access to flexibility and traded markets;
- by which the TSO ensures the overall balance of the gas system (at an aggregate and locational level); and
- for the settlement of individual shipper surpluses and deficits.

6.1 Access to flexibility and traded markets

In the previous chapters we considered the size of entry/exit regions and the arrangements for access to capacity and hence to customers. While these are clearly fundamental, it is also important that competing shippers can access gas commodity in a way which allows them to match the profile and flexibility of their commodity position to potential customer load.

There are a variety of sources of commodity (with varying degrees of flexibility) that shippers should be able to access. These include access to:

- imported gas under contract, either flat or with swing;
- gas at a trading hub (either sourced indigenously to the region, or released from other import contracts);
- storage capacity;
- customer interruption; and
- linepack.

In relation to the target model, we do not consider further access to imported gas under contract or access to storage capacity, as these are assumed to be dealt with through national arrangements which are unaffected (other than potentially in the structure and detailed design of contractual terms) by the nature of the target model.

We therefore focus on the arrangements for trading hubs, customer interruption and linepack.

6.1.1 Trading hubs

The development of trading hubs should essentially be a matter for market forces. If there are sufficient shippers with a demand to exchange commodity through standardised contracts then there should be value in the design of a standardised contract and arrangements to facilitate its trading. This is the basis on which exchanges and hubs in other commodities have developed, and it is not clear why the gas market is different in this regard. Intervention by sector regulators (as opposed to financial regulators of exchange trading) should be restricted to ensuring that the arrangements underlying the gas market do not act as a barrier to the commercial development of hubs.

The aspects of the gas market arrangements which are most likely to interact with the development of trading hubs include:

- the timing of capacity sales relative to the potential for commodity trading;
- the arrangements for nomination of flows to the TSO, as nominations will depend on commodity contract positions; and
- the timing of information provision from the TSO.

In order to ensure that these and other processes operated by the TSO do not create barriers to the development of trading hubs, there would be a rationale for an obligation on TSOs to design their externally facing processes taking into account the risk of such barriers developing.

6.1.2 Customer interruption

The potential for shippers to interrupt customers where demand is high can contribute significantly to gas flexibility. This is particularly the case when there are customers (such as power stations or large industrials) which are able to fuel switch (e.g. to distillate) relatively easily.

In competitive market segments, provided customers have the choice, shippers should be free to make interruptible as well as firm offers.

Customer interruption can also provide an important resource in the management of congestion on the network. Separately from shippers, there is therefore a rationale for the TSO (and potentially distribution network operators) to be able to interrupt customers on a commercial basis. Again, this should depend on customers having the choice (i.e. to be on an interruptible or firm contract).

However, TSO interruption is highly likely to be locational in nature. This may result in the opportunity for customers to exercise locational market power if they are allowed to quote a price for interruption. There may therefore also be a rationale to regulatory oversight or intervention in relation to TSO interruption arrangements.

6.1.3 Linepack

Depending on the characteristics of the gas system, linepack can provide an important source of flexibility. However, its effective management is also critical for system security. Given this link to system security, the management of linepack levels (i.e. control over the depletion and replenishment of linepack) should be the responsibility of the TSO.

However, for levels of linepack depletion and replenishment beyond those required by the TSO for system balancing, there is a rationale to providing shippers with the associated flexibility. If this flexibility is not provided to shippers, it will result in inefficient behaviour. Specifically, users will (in aggregate) be attempting to balance their injections and withdrawals of gas where this is unnecessary from the point of view of management of the system). They will therefore be incurring unnecessary costs, which will in due course be passed on to customers.

There are various ways in which system linepack could be provided to shippers. These trade off accuracy (i.e. ensuring that the arrangements reflect to shippers the capability of the system to deal with imbalances between injections and withdrawals by location) with simplicity (e.g. adopting a regional approach rather than reflecting locational variations in linepack).

The provision of access to linepack flexibility through an imbalance tolerance regime (i.e. where shippers are given a tolerance band within which they are more weakly incentivised to balance injections and load) may strike an appropriate balance between cost-reflectivity and simplicity. Approaches which attempt to treat linepack more like storage[15], while potentially more reflective of physical reality, result in significant complexity, particularly in relation to settlement and information provision.

6.2 Balancing

There will always be a requirement for a TSO to balance injections and withdrawals of gas across the network both on an aggregate level and by location (to take into account network capacity constraints).

In relation to the gas target model, the key questions relate to how this balancing role interacts with the gas market, and specifically:

15 For example, were each user to be allocated a "linepack storage" account, with this account being depleted if the user was short gas in a period and replenished if the user was long gas.

- the definition of the period for which the TSO has sole responsibility for balancing;
- whether there is a specific time at which the TSO "takes over" balancing from shippers; and
- how the TSO goes about procuring the commodity or capacity required for balancing.

6.2.1 Balancing period

The balancing period is the time period over which net long and short positions of participants are measured and settled. The arrangements for settling of imbalances across a balancing period (a subject to which we return below) should ensure that:

- shippers are paid for any net long position; and
- shippers are charged for any net short position.

The pricing of the settlement of these imbalances should be designed to incentivise parties to reach a balanced position across injections, withdrawals, purchases and sales over the balancing period. For example, if demand looks as if it will be higher than expected, shippers should be incentivised to buy energy from other shippers or increase planned import or production levels.

There is no incentive to achieve a balanced position within a balancing period. Since net positions are only measured across the period as a whole, there is no difference in financial outcome resulting from settlement of imbalances if a party:

- achieves a balance over the entire period;
- is long in the first half of the period and is short by the same volume in the second half; or
- is short in the first half of the period and long by the same volume in the second half.

As a result, the balancing period defines:

- the period over which shippers seek to achieve balanced positions; and
- the minimum duration of energy commodity product which is traded between shippers (as there is no incentive to trade a shorter duration of product).

The definition of the balancing period involves trading off cost-reflectivity and complexity (and potentially barriers to entry):

- A longer balancing period implies more costs of balancing are borne by the TSO (instead of shippers) and socialised among participants. However, it places fewer requirements on shippers to find sources of short term flexible gas to fine tune their positions. Particularly if there is a degree of concentration among the ownership or control of sources of short term flexibility within a region, this may encourage competition and new entry.

- A shorter balancing period ensures more costs of balancing are borne by shippers. However, to be able to manage these costs, shippers need to be able to respond to short term price signals relating to the extent of imbalance in the short term. This involves more complexity (for example, shippers are more likely to need round-the-clock trading organisations) and may, depending on the concentration of sources of short term gas, raise barriers to entry.

In European gas markets at present, there may be concerns over the degree of concentration of control of gas sources, and hence concerns regarding barriers to new entry and the ability of non-incumbent shippers to compete effectively for customers may be paramount. This would tend to push towards a longer definition of balancing period, such as the daily balancing arrangements which currently exist in a number of markets.

However, in taking this position, it will be important to consider the potential evolution of the European gas market.

As there is increasing pressure on the reduction of carbon emissions from the electricity sector through the connection of renewable generation sources, there is at least a strong potential that the demand for gas (from power generation) will become more volatile. Renewable sources of generation are intermittent over the day, and some form of backup generation is required if the lights are to stay on. If this generation is gas fired, this will mean that intraday renewables intermittency will be "imported" into gas demand.

This may become an important consideration because if gas demand becomes more volatile intraday, the adoption of a daily balancing period may result in increasing levels of balancing cost being socialised across the market rather than charged to those shippers that cause them. In other words, with greater levels of volatility, the ideal trade off between cost reflectivity and competition may change.

6.2.2 Timeline for TSO role

The second consideration in relation to balancing relates to whether there is a point at which the TSO "takes over" control of the gas system from a balancing perspective (or, put another way, whether there is a point in time beyond which renomination of gas flows by shippers must stop).

As we noted in the previous chapter, there are benefits to allowing renominations of gas flow by shippers for as long as is possible up to and during the day of gas delivery. This is because optimisation of daily positions by shippers is preferable to optimisation by the TSO (as noted above, within a daily balancing regime, intraday optimisation will have to be carried out by the TSO).

Therefore, unless it is required in order to secure the overall balance of the gas network, it would be preferable for the point at which the TSO takes over control of the gas system to be as late as possible during the gas day. The GB market is arguably an extreme example in which the TSO never takes full control, because shippers are able to continue trading gas for physical delivery through the gas day. The TSO trades both capacity and commodity during the gas day in parallel with shipper trading.

6.2.3 Procurement of balancing gas

To balance the system, TSOs may engage in a combination of short term trading in commodity and capacity. For example, TSOs may buy back capacity at specific points in order to reduce the absolute flow of gas to or from the system. Similarly, TSOs may purchase gas commodity to increase the overall injections of gas onto the system.

There is therefore a question about the way in which TSOs go about trading capacity and commodity. For example, some TSOs currently procure balancing gas through a suite of longer term contracts, whereas others procure gas on a short term exchange-based market.

TSOs are regulated entities, and the objective of national regulation (of network and system operation incentives) should be to incentivise operators to carry out their activities in a way would represent best value (in terms of the security of supply vs. cost trade off) for customers. Further, the optimal approach to procuring balancing gas is likely to vary from country to country (e.g. depending on the degree of competition from different sources of commodity which TSOs face).

Against this background, TSOs should be free to determine (subject to the incentives and obligations provided by the local regulatory regime) the most efficient approach to procuring balancing gas to provide system security. It should be recognised that the most efficient approach will vary from system to system.

6.3 Settlement

As we noted above, the arrangements for settlement of imbalances provide the incentive for shippers to trade gas *ex ante*. If shippers are short gas (i.e. their customers demanded more gas than they imported or purchased) and they are likely to face a high price for this short position, they will have an incentive to buy more gas. Similarly, if they are long and they are likely to be paid a relatively low price for their surplus gas, they will have an incentive to find a buyer *ex ante* who is willing to pay more.

As with the definition of the balancing period, there is a trade-off in the definition of imbalance prices between concerns relating to cost reflectivity and those relating to competition.

It may be that shippers being out of balance in particular periods causes significant costs for the relevant TSO, in which case cost reflectivity would indicate that those shippers should pay a high price for being short and receive a low price for being long. However, this will result in strong incentives to balance – which may create a barrier to entry if sources of short term gas which could be used to achieve a balanced position are in the hands of only a few shippers[16].

There are two key components to any imbalance regime, namely the definition of the imbalance volume (i.e. how short or long the shipper is) and the definition of the imbalance price. We consider these individual components in turn.

6.3.1 Volumes

The fundamental principle behind determining a shipper's imbalance volume is to estimate the extent to which a shipper's physical and contractual position has contributed to the overall extent to which the system has a net short or long gas position (i.e. the extent to which injections are respectively less than or greater than withdrawals).

The calculation should therefore be based on:

- the sum of physical withdrawals from the network related to an individual shipper (whether related to customer demand, storage injections or exports);
- the sum of physical injections to the network (whether related to production, storage withdrawals or imports); and
- the net purchases or sales of gas by that shipper from others within the region.

This calculation should be applied in a non-discriminatory way to all shippers and in relation to all customer classes.

However, as we noted above in relation to linepack, there is also a rationale for small imbalance volumes to be treated differently to larger imbalances, as provided there is some linepack not required for system balancing, the TSO may

[16] We note that the strength of incentives to balance may also link to security of supply issues, as the less incentive shippers have to trade to balance, the more reliance there may be on the TSO entering the market for short term gas if there is an aggregate shortage, and hence a risk that there are insufficient offers on the short term markets.

not have to take balancing actions to correct for small aggregate imbalances between injections and withdrawals.

The initial volume of aggregate tolerance provided to shippers should therefore be based on available linepack levels. There may also be situations (particularly if the alternate sources of flexibility are relatively concentrated) in which it is desirable for the TSO to be able to sell additional tolerance levels (contingent on network conditions permitting). However, bilateral trading of tolerance between shippers is potentially less desirable (at least without the consent of the TSO), as there is the potential for shippers to acquire tolerance levels which are not consistent with local network conditions.

6.3.2 Prices

As we noted above, imbalance prices should incentivise shippers to balance across the balancing period by providing a price signal which is reflective of the costs incurred by the TSO in balancing the system. A stronger incentive will result in shippers expending too much effort (relative to the cost to the TSO) to balance, and a weaker incentive will result in too little effort being expended.

Therefore, there is a strong rationale for the TSO's short term gas costs (from whatever short and long term gas portfolio they used to balance the system) to determine both the level and spread between "system buy" and "system sell" prices. However, in undertaking this calculation care will need to be taken to ensure that:

- gas transactions undertaken for network management purposes (i.e. to manage congestion) rather than for balancing of aggregate demand and supply are excluded from such calculations, as they would tend to be priced differently; and
- gas transactions in which there is a risk that market power was exercised against the TSO cannot unduly influence the determination of imbalance prices.

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