

**METHODOLOGIES FOR ESTABLISHING NATIONAL
AND CROSS-BORDER SYSTEMS OF
PRICING OF ACCESS TO THE GAS SYSTEM IN EUROPE**

17 February 2000

Prepared for the European Commission by:

The Brattle Group
8-12 Brook Street, 5th Floor
London W1Y 1AA
United Kingdom
(+44)(0)20-7491-0843
office@brattle.co.uk

Table of Contents

EXECUTIVE SUMMARY	3
MAIN REPORT	16
1. Introduction.....	17
1.1. Market Evolution.....	17
1.2. Required Services.....	18
1.3. Pricing of Services.....	20
1.4. Balancing, Storage and Trading	21
1.5. Security of Supply, Take-or-Pay and PSOs	22
1.6. Harmonisation	23
1.7. Next Steps	23
1.8. Structure of Report	23
2. The European Gas Industry on the Eve of Liberalisation	24
2.1. Market Structure.....	24
2.2. Current Cross-border Flows and Existing Tariffs	25
3. Principles of the Gas Directive	28
3.1. Non-Discrimination	28
3.2. Establishing a Competitive Market	29
3.3. Interconnection and Interoperability	30
3.4. Negotiated Access	31
3.5. Unbundling	33
4. Required Services.....	35
4.1. Capacity Rights	35
4.2. Interruptible or “On-Demand” Service.....	44
4.3. The Flexibility to Negotiate “Customised Services”	48
5. Pricing of Services	51
5.1. Tariff Regime and Total Revenues.....	51
5.2. Design of Charges for Individual Services	59
5.3. Pricing Methodology and Cross-Border Transactions.....	62
6. Balancing, Storage and Trading	75
6.1. Balancing Rules and Imbalance Charges.....	75
6.2. Storage	78
6.3. Trading Mechanisms	81
7. Security of Supply, Take-or-Pay and PSOs	84
7.1. Security of Supply	84
7.2. Take-or-Pay Contracts and Pipeline Access	87
8. Harmonisation.....	89
9. Next Steps	91
APPENDICES	92
Appendix 1: Comparison of Existing Tariffs.....	93
Appendix 2: Important Distinctions between Gas and Electricity	95
Appendix 3: Summary of Questionnaire Responses	97

Appendix 4: The Gas Industry Standards Board.....	105
Appendix 5: Preventing Discrimination in Capacity Auctions	110
Appendix 6: Alternative Methodologies for Regulatory Rate-Making	112

EXECUTIVE SUMMARY

EXECUTIVE SUMMARY

This study applies the general principles embodied in the Gas Directive (98/30/EC) to produce recommendations concerning *price and non-price terms for natural gas transportation services*. The study focuses on the implications of price and non-price terms for the development of cross-border trade and a single, unified European gas market. Our interpretation of the Directive emphasises the principle of *non-discrimination*, the goal of establishing a *competitive natural gas market*, and the promotion of *interconnection and interoperability*. The study's recommendations are designed to ensure effective and complete implementation of the Directive, in order to secure in full the potential benefits of liberalisation, which include lower prices for consumers, greater efficiency of system usage and development, and more efficient upstream investment.

1. Market Evolution

Full implementation of the Directive will involve a significant transition from the current state of most European gas markets. Experience suggests that this transformation will take several years, and that the appropriate pricing and service concepts will depend on the stage of market evolution. Different Member States may be starting at different evolutionary stages and proceed at different paces as the transition unfolds. *Our report therefore distinguishes where necessary between recommendations and conclusions that apply during different phases of the market transformation process.* We summarise the requirements and distinguishing characteristics of these phases in Table 1, attached at the end of this Summary.

2. Principles of the Directive

Our report begins by discussing those principles underlying the Directive which have the most significant implications for open access and cross-border trade.

Non-Discrimination

The principle of non-discrimination affects many aspects of the Directive's implementation. It has special significance where, as in many Member States, transportation and distribution networks belong to vertically integrated undertakings. In interpreting the Directive, it is necessary to determine the extent to which *non-discrimination requires such an entity to make available to entrants the range of services that is available to its related undertakings*. We argue that *access terms that are formally non-discriminatory, but whose economic effect is to unreasonably disadvantage certain classes of customers, are discriminatory in the economic sense*. To respect the principle of non-discrimination, *tariffs should reflect costs in a broad sense*.

Establishing a Competitive Market

The principle of a competitive market has a number of significant implications. First, *it reinforces concerns over discrimination in many areas*. Second, *firms in competitive markets can not expect to earn monopoly profits*. Third, *prices in competitive markets are*

necessarily cost-reflective (except where distortions are necessary and sustainable to facilitate legitimate public-service obligations), because the possibility of entry rules out cross-subsidisation of activities. Fourth, competitive markets ensure efficient use of all system assets. In particular, they tend to *maximise usage of capacity* and to *foster efficient capacity expansion*. Fifth, effective competition often entails the creation of *trading institutions* such as hubs, spot and forward markets (for gas itself and for transportation capacity), trading instruments such as swaps and futures, and involves actors such as traders, brokers and load aggregators who facilitate trade and promote market liquidity.

Interconnection and Interoperability

The promotion of *interconnection and interoperability* of systems is inherent to the completion of the internal market, and has significant implications for the *harmonisation of standards across systems and across national boundaries*. Experience in mature gas markets elsewhere suggests that *voluntary action* by industry participants can produce the required degree of harmonisation in a manner that is non-discriminatory and enhances competition. However, it is essential that any industry body that promotes standards for the implementation of the Directive represent the interests and opinions of all market participants.

Negotiated Access

We distinguish between two interpretations of “negotiated access”. Under the first, the Transmission Operator¹ (“TO”) has *initial flexibility in designing the price and non-price terms of access*. These terms may be negotiated between the TO and potential customers. Once determined, *they must be published in sufficient detail to ensure transparency and non-discrimination, and applied in a consistent and objective fashion to all parties, including its own affiliates*. These terms define a set of “basic services” that are available to third parties without subsequent negotiation. Member States may choose to give the TO the right, subsequent to publication, to negotiate non-standard access terms for individual customers, on a case-by-case basis, and as a supplement to the provision of the “basic services”. However, such a right is balanced by rigorous safeguards against abuse.

The second interpretation of negotiated access is very different. It imagines that the TO is free to negotiate each contract on a case-by-case basis, in a *laissez-faire* manner and with few safeguards. In particular, the second interpretation omits the requirement to make available standard “basic services”. Negotiation would therefore entail a process of inquiring and awaiting responses concerning the availability, terms and cost of transmission services.

Until gas markets are mature, the second of these interpretations would be highly counter-productive. Without the safeguards envisaged under the first interpretation

¹ By “transmission operator” we understand any person or body responsible for the operation of a significant part of any (downstream) natural gas transportation infrastructure.

above, negotiations are unlikely to “operate in accordance with objective, transparent and non-discriminatory criteria”, as required by Article 14 of the Directive. Until markets are mature, implementation of negotiated access in such a laissez-faire manner is also likely to lead to breaches of other provisions of the Directive, and of general competition law. The absence of proper safeguards would facilitate abuse of a dominant position by incumbent TOs to discriminate against entrants, and would prevent the creation of a unified, competitive natural gas market in Europe.

Unbundling

The Directive contains a number of safeguards against abuse by vertically integrated undertakings. However, experience elsewhere demonstrates that *such provisions are effective only when accompanied by strong regulatory oversight.*² Experience in the United Kingdom suggests that, *although not explicitly required by the Directive, the creation of separate subsidiaries with separate business premises will help prevent the abuse of commercially sensitive information.*

3. Conclusions and Recommendations of the Report

The report proceeds to discuss in detail each of the elements of an open access regime:

- Required Services
- Pricing of Services
- Balancing, Storage and Trading
- Security of Supply, Take-or-Pay and PSOs
- Harmonisation

It ends with a brief discussion of next steps required to implement its recommendations.

Main Conclusions and Recommendations

1. Required Services

Capacity Rights

1. TOs should ensure that spare capacity rights are made available to all users on a firm basis, with full rights to the use or remarketing of the associated capacity.

² This problem was identified by competition authorities in the United Kingdom with respect to British Gas. A full discussion can be found in P.R. Carpenter and C. Lapuerta, “A Critique of Light-Handed Regulation: The Case of British Gas”, in the *Northwestern Journal of International Law and Business*, Spring 1999, Vol. 19, Number 3, pp. 479-497.

2. Existing capacity rights should be respected. However, “spare” capacity rights include rights that become available as contracts expire, or customers switch away from the incumbent. Allocation of rights should be non-discriminatory, and in particular existing rights holders should not receive preferential treatment.
3. If (contrary to our recommendations below) an “on-demand” interruptible service is not available, then it may be desirable to impose “use-or-lose” requirements on existing capacity holders.
4. Initially, we recommend auctions for the allocation of spare firm capacity among market participants. However, rigorous safeguards are required to prevent abuse by vertically-integrated pipeline owners.
5. After markets have developed, allocation by “first-come, first-served” or lotteries can be considered. However, we recommend against “beauty contests”.
6. Firm capacity rights should be tradable with no requirements for advance notification or consent from the TO.
7. TOs should be required to publish timely and detailed information on the existing and projected availability of spare firm capacity on their systems, while protecting the identity of capacity rights holders.
8. Some agreed fraction of spare capacity in each pipeline should be reserved for a firm capacity service of no more than one year in duration. The remainder can be subject to multi-year contracts. Industry participants should decide on an appropriate split between annual and multi-year capacity rights.
9. The definition of capacity rights should allow for flexibility in the choice of receipt and delivery points.
10. Industry participants should also harmonise the definition of firm capacity rights, as well as nomination, allocation and settlement procedures.

Interruptible Service

1. During the transition to developed gas markets, TOs should be required to offer a short-term interruptible (“on-demand”) service.
2. The price for interruptible service should be capped at the price of firm service on a 100% load-factor basis.
3. Interruptible service can be priced above short-term variable cost. However, if the price is significantly above short-term variable cost then the vast majority of the operating profit earned from such service should be returned to holders of firm capacity rights by some form of revenue crediting mechanism.
4. For interruptible service to be effective, TOs should publish timely and detailed information about the use of the system and its capacity.
5. Industry participants should agree standards for the terms of interruptible service.

Negotiated Service Flexibility

1. In recently liberalised markets, the existence of “negotiated access” should not be interpreted in a *laissez-faire* sense that would necessarily entail a process of inquiring, waiting for responses and bargaining to derive final terms for service.
2. TOs in “negotiated access” regimes should develop standardised terms of basic services that can allow their purchase by third parties in a matter of hours, rather than days or weeks.
3. In addition to the basic services, Member States may wish to allow TOs the right to negotiate non-standard access terms with individual customers on a case-by-case basis. However, until a market is mature, the negotiation of customised services should be accompanied by rigorous safeguards. The basic, non-negotiated services should still be available; the terms and conditions of any customer-specific services agreed in negotiations should be published; and the regulator or dispute-settlement authority should actively scrutinise such arrangements for signs of discrimination, and be empowered to impose effective sanctions if necessary.
4. The published prices for the basic services cannot represent an initial bargaining position by the TO, and should be no higher than justified by a transparent tariff model that measures and allocates the operating and capital costs of the system to all services.
5. These safeguards can be relaxed only when the market is judged to be mature. The market’s maturity should be measured by the ability of customers to derive their own customised services by engaging in secondary market transactions rather than negotiating directly with the pipeline.

2. Pricing of Services

Tariff Regime and Total Revenues

1. Pipeline transportation charges in both regulated and negotiated access regimes should derive from transparent tariff models. Charges should satisfy the “NPV test”, which is a standard part of regulatory accounting methodology. It requires that pipeline charges recover on expectation no more than operating costs, taxes, depreciation and the cost of capital on existing investment.
2. Charges in excess of those given by the NPV test contain an element of monopoly profit and are therefore inconsistent with the Directive and with EU competition law.
3. We recommend the use of the rate-making methodology known as “economic depreciation”, which produces steady real charges over time.
4. The initial valuation of the pipeline system for a privatised TO should be derived by reference to the purchase price.

5. For assets still owned by the government, the initial valuation of pipeline assets should not exceed depreciated replacement costs unless an affirmative demonstration can be made that the resulting charges would not affect competition adversely. Care should also be taken to ensure that asset values that reflect prior government subsidies do not impede the construction of new pipes. This may require compensation between pipelines for the effects of prior subsidisation.
6. For TOs that have always been private, the following rules should apply to the initial asset value:
 - a) the assets should be valued at their depreciated book value, unless the TO can demonstrate that capital recovery to date has been less than indicated by the cumulative depreciation figure;
 - b) upward revaluations of pipeline assets on the eve of liberalisation should not be allowed; and,
 - c) total valuation should not exceed the depreciated optimised replacement cost of a new pipeline.
7. The cost of capital used to derive tariffs should itself be derived from one of the several widely-used financial methodologies. The analysis should be in a transparent form, open to assessment by third parties.
8. Replacement cost valuation techniques should not be used in negotiated access regimes.
9. Changes in the rate-making or asset valuation methodologies of a tariff model should not be allowed to generate windfall gains or losses.

Design of Charges for Individual Services

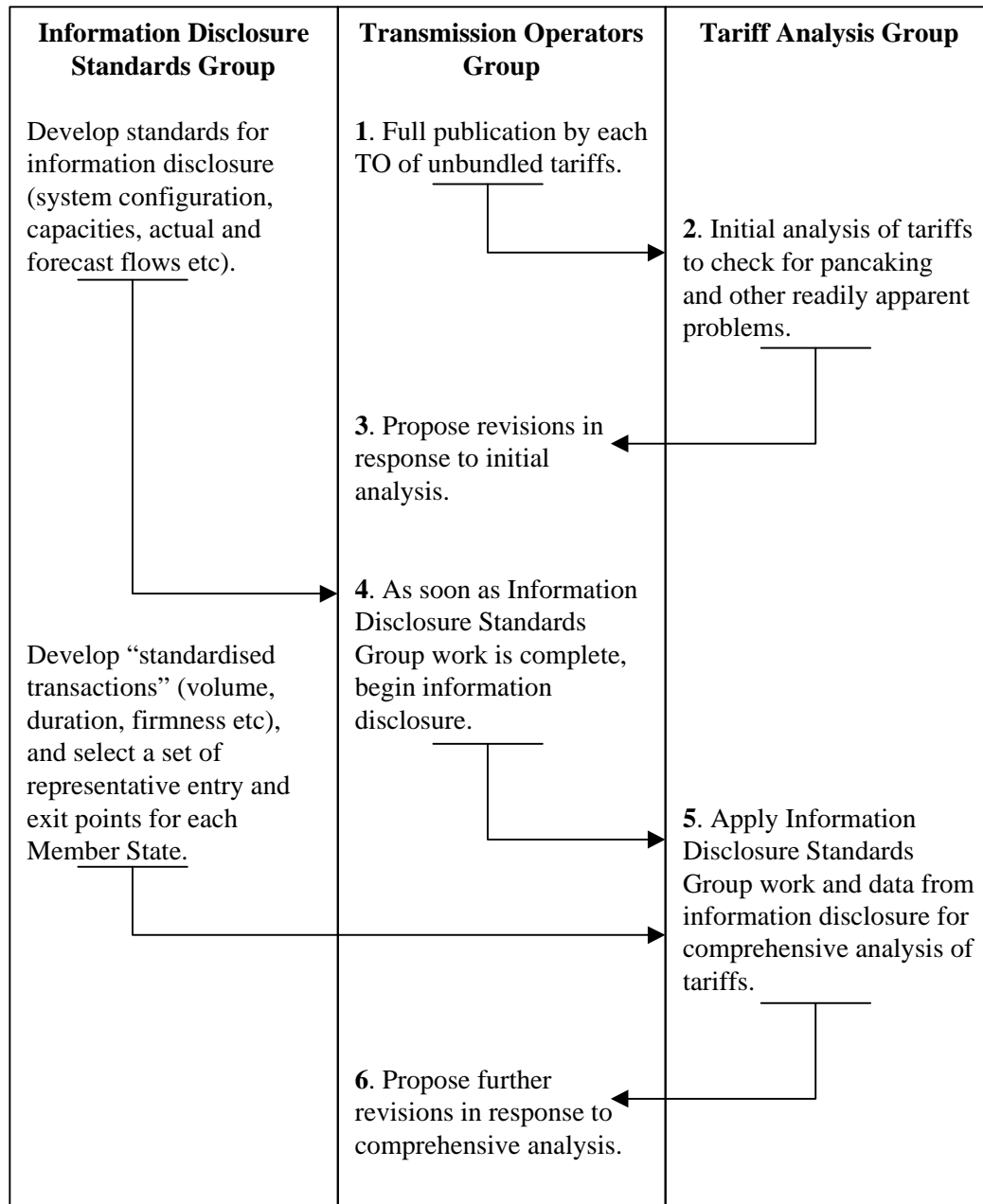
1. The fixed costs of the transportation system should be allocated to capacity charges for firm capacity.
2. “Commodity” or “usage” charges should be designed to recover no more than the variable costs of transportation.
3. Fixed costs should typically not be allocated to transactions such as swaps that tend to alleviate congestion.

Pricing Methodology and Cross-Border Transactions

1. There is no single pricing methodology that guarantees appropriate treatment of cross-border flows. Member States should ensure that, whatever methodology is employed, cross-border pricing reflects the principle of “broad cost-reflectivity”. This entails:
 - Assessment of the system configuration and likely prevailing flows for each interconnected system.

- Significant cost differentials, such as the savings arising from likely backhaul transactions, should be identified in this assessment.
 - This exercise should be conducted both on a national level, and at a supra-national or Community level.
 - The particular pricing methodology chosen should provide as much simplicity and transparency as possible, while allowing for price differentials that reflect the cost differentials identified above.
2. Postage stamp and zonal pricing systems may result in “pancaking” of charges for cross-border flows. Depending on the configuration of the pipeline system, the problem may be resolved by exempting the cross-border flow from the postage stamp or zonal rate in either the originating or terminating country. However, this solution may simultaneously create a need for supplementary payments between interconnected systems.
 3. In “entry/exit” systems, appropriate treatment of cross-border transactions depends on whether the interconnection involves a significant amount of dedicated assets. If it does not, then there may be no need for a separate “entry” or “exit” charge for the point of interconnection. In cases like the Irish interconnector or the European interconnector, however, separate “entry and exit” charges at the interconnection point or a separate charge for use of the interconnection assets are appropriate.
 4. A “path-based” charging system can avoid discrimination against cross-border flows, but may be excessively complex and offer insufficient flexibility in many systems. In general a zonal system with a sufficient number of zones to ensure that tariffs capture key determinants of cost is preferable to a “pure” path-based system where charges depend on the exact combination of entry and exit points. An alternative suggestion is to use separate “path-based” charges for transit through a country, while using another charging method for transactions that originate or terminate domestically. However, such a “hybrid” scheme should be rigorously scrutinised for potential discrimination.
 5. To ensure timely and effective implementation of these recommendations, a process should be employed along the lines described in Figure E1 below. Where consensus cannot be reached, the regulator or dispute settlement authority should be empowered to impose an appropriate system.

Figure E1: Implementation of Tariff Methodology Recommendations



3. Balancing, Storage and Trading

Balancing Rules and Imbalance Charges

1. There should be consistency between the amount and type of system resources retained by the TO for system balancing purposes, the stringency of the balancing tolerances required, and the size of any imbalance penalties. TOs should have the burden to demonstrate that such consistency has been achieved, and that their balancing rules and imbalance charges are consistent with the pro-competitive and non-discriminatory principles of the Directive.

2. Outside Europe it is rare for pipelines to impose less than monthly balancing requirements. There are only a few systems that impose daily balancing requirements and none, to our knowledge, require hourly balancing. The use of hourly balancing, as proposed by Gasunie and some others in Europe is the worldwide exception to the rule.
3. Before it is accepted that hourly balancing is an appropriate protocol, TOs should demonstrate that they cannot avoid stringent balancing tolerances on the basis of the system resources (storage, pipeline capacity and linepack) available to them.
4. Third parties should be allowed to aggregate and/or trade their imbalance positions. TOs should provide regular and timely information to each shipper as to the size of its imbalance position and the coincident linepack status of the system.
5. The same principles developed for balancing services apply, *mutatis mutandis*, to quality conversion services. In particular, the TO should show that any charges for quality conversion are cost-reflective.
6. It will be useful to convene as soon as practicable a meeting of industry participants to discuss and agree the harmonisation of balancing rules and protocols, particularly as they may affect interstate trade.

Storage

1. Although the Directive does not explicitly mandate access to storage, it is critical for efficiency, the development of competition, and preventing discrimination. We conclude that, even if direct access to storage is not provided, the principles of the Directive require vertically integrated incumbents to provide “virtual storage” if their affiliates enjoy the flexibility provided by storage assets.
2. The general *service* principles discussed above apply to storage as well, including the offer of tradable firm capacity rights, the allocation of rights, the provision of an “on-demand” interruptible service, and the publication of information.
3. The general *pricing* principles discussed above also apply to storage, including the use of transparent tariff models that meet the “NPV test”, our recommendations concerning asset valuation, the allocation of fixed costs to firm capacity, and the design of any “injection” or “withdrawal” charges to recover variable costs only.

Trading Mechanisms

1. The Directive’s principles of efficiency, competition, and non-discrimination generally support policies designed to encourage financial trading of gas and transportation rights as well as physical trading.
2. Ownership of physical assets should not be a pre-requisite to trading.

3. To facilitate swaps, changes to nominations should be allowed without penalty up to reasonable deadlines. The pooling and trading of imbalances should also be allowed to help shippers minimise imbalance positions and avoid imbalance charges.

4. Security of Supply, Take-or-Pay and PSOs

Security of Supply

1. Liberalised markets tend naturally to enhance security of supply. Security of supply concerns do not justify intervention in market processes except in particular and exceptional circumstances.
2. While take-or-pay contracts may continue to play an important role in European gas markets, they are not required for security of supply in a mature market.
3. Denying access to storage assets does not increase security of supply.
4. In exceptional circumstances market intervention might be justified by security of supply concerns. However, the principles of the Directive require an affirmative demonstration that any such measures are required. The demonstration should:
 - identify a specific market failure that the intervention is intended to redress;
 - demonstrate that the proposed measures are tailored to the problem and minimise market distortions; and,
 - show that the measures will be implemented in the most transparent and least discriminatory manner possible.

Take-or-Pay Contracts

1. Take-or-pay derogations should not be granted unless the TO demonstrates that reasonable avenues to renegotiate contracts have already been exhausted, that open access would threaten financial solvency, and that no additional equity capital can be raised. Objective evidence such as poor credit ratings or liquidity ratios should be required.
2. If a derogation or temporary increase in charges is allowed, the terms should be strict. Any such measure should be for as short a time as possible, with periodic checks of its continuing need.
3. Derogations and other relief should end as past take-or-pay contracts expire.
4. There is no reason to provide derogations for contracts that were signed after market participants could reasonably foresee open access.

5. Harmonisation

1. Where it is required, harmonisation should be promoted via voluntary industry action rather than regulatory or legislative fiat.

2. As an essential safeguard against discrimination, any industry body involved in proposing harmonisation measures should reflect the views of all classes of market participants, including potential third party entrants.
3. Harmonisation is required in a number of areas, including: the definition of firm capacity rights; nomination procedures, gas allocation procedures and settlement mechanisms; rate-making methodology and asset valuation when different pipes compete; design of charges (the fix/variable split); balancing rules and protocols.

6. Next Steps

Our report suggests two sets of concrete measures to further the implementation of particular parts of its recommendations. These suggestions are in no way intended to be exhaustive. Rather, they focus on areas that require co-ordinated action by European market participants.

First, in relation to the choice of pricing methodology and its implications for cross-border transactions, we recommended the process summarised in Figure E1 above. Second, in relation to required harmonisation measures, we recommended the voluntary formation of an industry group, with extremely broad membership, to help determine European standards for natural gas. Where consensus cannot be reached, the regulator or dispute settlement authority should be empowered to impose appropriate standards.

7. Structure of Report

The rest of this report is structured as follows. We briefly outline the current state of the European natural gas industry, describing the market history and structure, as well as the major cross-border flows that currently occur. We then discuss those aspects of the Gas Directive that are of the greatest significance in relation to open access and cross-border trade: non-discrimination, the creation of a competitive market, interconnection and interoperability, the interpretation of negotiated access, and issues related to unbundling.

We proceed to apply the principles of the Directive to each of the most important elements or “building blocks” of open access. We first describe the services that should be made available to third parties: firm capacity rights, interruptible service, and “customised” services under appropriate circumstances. Second we examine how these services should be priced, addressing the determination of the appropriate total revenue, the design of charges for individual services, and the pricing of cross-border transactions. We then discuss a series of complementary issues: balancing rules and protocols, storage, trading mechanisms, security of supply, and take-or-pay contracts. Finally we summarise our recommendations concerning which elements of open access require harmonisation, and how such harmonisation should best be achieved, and briefly discuss some next steps towards implementation of our recommendations.

Table 1: Sequencing of Implementation Measures

	Before Implementation	Transition	Fully Mature Market
Firm Service	<ul style="list-style-type: none"> • Multiple-year contracts • Bundled • Take or pay • Capacity allocation at discretion of TO 	<ul style="list-style-type: none"> • Unbundled firm rights • No preference to incumbents for contract renewal • Objective capacity allocation rules 	<ul style="list-style-type: none"> • Secondary markets provide greater scope for choice of capacity allocation rules
Interruptible Service	<ul style="list-style-type: none"> • No interruptible service for third parties 	<ul style="list-style-type: none"> • TOs required to offer “on demand” interruptible service 	<ul style="list-style-type: none"> • Liquid secondary market eliminates need for interruptible service obligation
Pricing of Transportation	<ul style="list-style-type: none"> • Individually negotiated contracts • No transparent tariff model 	<ul style="list-style-type: none"> • Standard tariffs required • Transparent tariff models • Cost-reflectivity required for individual services 	<ul style="list-style-type: none"> • Strict rules remain for pricing of basic services • Greater scope for negotiating customised service prices
Capacity Booking System	<ul style="list-style-type: none"> • One-off contracting 	<ul style="list-style-type: none"> • Standardised terms • Booking by third parties allowed 	<ul style="list-style-type: none"> • Same as during transition
Information	<ul style="list-style-type: none"> • No publication of prices, capacity availability, or system information 	<ul style="list-style-type: none"> • Extensive and frequent publication required • Identities of rights holders protected 	<ul style="list-style-type: none"> • TOs acquire natural incentives to publish information
Markets	<ul style="list-style-type: none"> • Restrictions on transfers of rights • Few participants • Physical trading only 	<ul style="list-style-type: none"> • TOs must facilitate firm right transfers • Harmonisation, preferably voluntary, to facilitate trading 	<ul style="list-style-type: none"> • Full range of physical and financial markets in gas and transportation capacity

MAIN REPORT

1. Introduction

This study applies the general principles embodied in the Gas Directive to produce recommendations concerning price and non-price terms for *natural gas transportation services*.³⁴ We focus on the implications of price and non-price terms for the development of cross-border trade and a single, unified European gas market. Our interpretation of the Directive emphasises the principle of *non-discrimination*, the goal of establishing a *competitive natural gas market*, and the promotion of *interconnection and interoperability*. We have kept in mind the principle of subsidiarity and the desirability of ensuring that regulatory requirements are imposed only where market-based and voluntary solutions are infeasible. In addition, we recognise the importance of *security of supply*.

Our analysis examines both price and non-price terms of access. Prices and pricing methodologies must be analysed in the context of the services involved and particular and changing market conditions. Standards have not yet evolved concerning the natural gas transportation services that should be made available to third parties in Europe, and markets can be expected to experience significant changes as the Directive is implemented. As a necessary prelude to our pricing analysis, we therefore provide a vision of the expected market evolution and the nature and type of services that should be offered to implement the principles of the Directive.

1.1. Market Evolution

With the principal exception of the United Kingdom, the natural gas industry in most Member States is currently dominated by one or a few vertically-integrated incumbents. Transportation is still largely bundled with gas sales in long-term contracts that contain take-or-pay provisions and that cannot easily be transferred among market participants. As contracts expire or as new capacity is added, TOs exercise discretion on the allocation of capacity to affiliates or third parties. Short-term interruptible service is not available to third parties. Service bundling implies that transportation services are often not priced separately, nor are prices derived from transparent tariff models. Provisions do not generally exist that ensure cost-reflective prices. Little information on pipeline systems or prices is publicly available. Liquid secondary markets do not yet exist for pipeline capacity or for short-term gas sales. Some companies negotiate long-term “swaps” that improve the efficiency of physical flows, but each contract requires individual

³ We use the term “transportation services” to apply to both the transmission and distribution of natural gas. References in this report to transportation (including the term “Transmission Operator”) should generally be taken to apply also, *mutatis mutandis*, to distribution.

⁴ Similar principles underlie the Electricity Directive, and many of the issues considered in our report arise also in electricity markets. However, there are also significant differences between the two industries, that affect the design and pricing of transmission services between the two industries. In our opinion it would not be appropriate to simply “copy” the arrangements for electric power to the gas industry. Appendix 2 of this report outlines the most relevant differences between the two industries.

negotiation. The bulk of gas trading is physical in nature, as purely “financial trades” have not yet become common.

We believe that the goals of the Directive involve a serious transition from the current state of most European gas markets. The development of a unified, competitive market will involve the unbundling of transportation services from sales, increased availability of short-term services to third parties, and less reliance on take-or-pay contracts. Much more information will be available concerning pipeline operations and prices, and pipelines will justify their charges for different services by reference to underlying costs. Pipeline capacity will be distributed among a greater diversity of market participants, who will be able to trade capacity with each other as their needs and market conditions change. Secondary markets in pipeline capacity will involve both short-term and long-term transactions, and will follow the general development of liquid spot and forward markets in natural gas itself. Short-term swaps will become more feasible. Brokers and traders who engage solely in “financial” trades will arise. By aggregating the loads of different customers, financial intermediaries will reduce the need to negotiate “swap” contracts on a bilateral basis.

Experience suggests that this transformation will take several years, and that the appropriate pricing and service concepts will depend on the stage of market evolution. Different Member States may be starting at different evolutionary stages and proceed at different paces as the transition unfolds. Our report therefore distinguishes where necessary between recommendations and conclusions that apply during different phases of the market transformation process. We summarise the requirements and distinguishing characteristics of these phases in Table 1, attached at the end of the Executive Summary.

1.2. Required Services

As a first and fundamental step in the creation of a competitive and non-discriminatory market regime, we conclude that *spare firm capacity rights should be made available to all pipeline users*. International experience indicates that the failure to provide services that include a firm capacity entitlement impedes the development of liquid secondary markets in pipeline capacity, even where the risk of interruption is distributed among market participants in a non-discriminatory manner. We believe that it will be generally practical to seek to reallocate existing capacity rights under the Directive only under relatively limited circumstances. Existing capacity allocations should not be allowed to create a situation where frequent denial of access occurs in the absence of genuine physical congestion. Regulatory authorities should examine closely any recent long-term contracts that may have the purpose of preventing the creation of spare capacity. Existing capacity holders should have no “right of first refusal” when contracts expire.

The Directive’s principles of competition and non-discrimination have several implications for the allocation of capacity rights. TOs cannot employ subjective criteria for allocating rights, should not be allowed to grant “rights of first refusals” to affiliates or incumbents for incremental capacity, and should not interfere with the exchange of capacity rights among third parties. In particular, the Directive’s concerns with the abuse

of commercially sensitive information imply that capacity trades should not require prior notification of the TO. Furthermore, to increase the diversity of participants in gas markets, capacity rights should not be restricted to long-term contracts. We recommend that market participants, including the regulatory authorities, meet and agree to reserve a portion of spare capacity for one-year contracts. The regulator or dispute-settlement authority should ensure that incumbents participate fully and in good faith.

The ability of third parties to purchase firm capacity rights will only be meaningful if pipelines *publish information on the extent of current and future capacity availability*. Publication should, however, take place without revealing commercially sensitive information about the identities of capacity holders. As markets mature, natural incentives will arise for TOs to provide relevant information about their systems, but we believe that the provision of information should be a fundamental requirement in the early stages of the Directive's Implementation.

There are various methods for allocating available firm capacity rights, including "first-come, first-served", "beauty contests", lotteries and auctions for allocating scarce capacity. Each of these methods has its own advantages and disadvantages, whose weights vary according to specific market conditions. We recommend against the use of "beauty contests" at any time, and against "first-come, first-served" during the early stages of market development. We favour the use of auctions rather than lotteries, provided that rigorous safeguards are in place to prevent abuse. Once markets are fully developed, any of these methods except for "beauty contests" can be considered.

Finally, we note that some aspects of firm capacity rights should be harmonised across Member States. Prior to the development of liquid secondary markets, voluntary negotiations amongst market participants may be necessary to ensure harmonisation, provided that the resulting standards are efficient and non-discriminatory. However, as liquid secondary markets in pipeline capacity develop, the need for harmonisation will decrease. For example, in a mature market it might not be necessary for interconnected TOs to offer firm capacity contracts that are perfectly synchronised in time. One TO could offer five-year capacity contracts while an interconnected TO could offer ten-year contracts without threatening the development of a single European market, as long as the capacity rights can be reallocated and "repackaged" by others in the secondary market to achieve harmonisation naturally.

In the first few years of implementing the Directive, we conclude that *firm capacity rights should be supplemented by an "on demand" interruptible service at reasonable cost*.⁵ However, once liquid secondary markets have developed and matured, they will naturally provide the same flexibility as an "on demand" interruptible service, and a corresponding obligation need not be imposed directly on the pipelines.

⁵ Under an "interruptible service" agreement, the transmission operator agrees to transmit the counterparty's gas provided the requisite capacity is available, but in contrast to "firm" service provides no guarantee of availability. Interruptible service may also be provided with some specified probability of service availability.

Firm capacity rights and “on-demand” interruptible service are necessary for competition, efficiency and non-discrimination. However, the requirement to provide these services should not constrain the flexibility of TOs to offer supplementary services in a competitive market. The scope for negotiations of services with different customers will depend on the maturity of the market. *In the first years of implementing the Directive, case-by-case negotiations pose a significant risk of discrimination among market participants, and the delays involved can prevent the development of crucial short-term markets in gas and transportation.* We therefore recommend an extremely limited scope to individual customer negotiations during this period unless rigorous safeguards are in place, including publication requirements and active scrutiny by a regulator empowered to impose effective sanctions on discriminatory behaviour. As we explain below, we do not believe that “negotiated access” should be interpreted as allowing system operators extensive discretion to engage in case-by-case negotiation concerning basic services.

Once a *market has matured*, negotiations of customised services can be compatible with the principle of non-discrimination. By that time, the basic firm and “on-demand” interruptible services will have demonstrated themselves to be *sufficiently comprehensive and attractive to permit effective competition*. Liberalisation experience elsewhere in the world has demonstrated that once such competition is established, third parties will enter the business of “repackaging” basic services in secondary markets to compete with the pipeline’s negotiated solutions. Once these conditions are met, TOs may be allowed considerable flexibility in devising and pricing supplementary services for individual customers.

1.3. Pricing of Services

Given this vision of transportation services, we analyse the pricing principles that should apply to firm capacity rights and “on demand” interruptible service. *Pipelines should devise tariffs that, in the aggregate, are expected to provide sufficient revenues to cover efficient operating costs, taxes, depreciation and the cost of capital, but that do not contain any element of monopoly profit.* Several regulatory accounting systems are compatible with this requirement, such as those based on “historical costs”, “trended costs”, “depreciated replacement costs”, or “economic depreciation”. We explain how each methodology can be implemented in a manner consistent with the Directive, and we warn of particular pitfalls. We also believe that the inherent discretion involved in the “depreciated replacement cost” methodology renders it *inappropriate* for pipelines in negotiated access jurisdictions. Furthermore, the choice of tariff methodology should be guided by the principles of avoiding distorted competition between pipelines and of providing efficient signals for capacity expansion.

We recommend certain guidelines for the valuation of the initial asset base in such models.

- For pipelines that have been recently privatised, we recommend the use of the pipeline’s purchase price from the government to determine the initial asset base.
- For pipelines that have always been private, or that remain under government control, we recommend the following rule: the regulatory asset base should not

exceed the net book value of the assets, unless the TO can demonstrate that implicit charges to date have not recovered the depreciation on the accounts. We discuss the specific requirements to make such a demonstration.

- Upward revaluations of assets performed on the eve of market liberalisation should not be allowed.
- The regulatory asset base should typically be no greater than the depreciated optimised replacement cost of the pipeline.

Transportation charges should promote efficient system utilisation, subject to the conditions of avoiding both monopoly profits and discrimination. *The fixed costs of a pipeline system should be allocated principally to the charges for firm capacity rights, which should not depend on actual throughput. Any “commodity charge” per unit of throughput should be designed to recover variable costs only. Transactions such as “backhauls” that help relieve capacity constraints should not pay for the fixed costs of the system. “On demand” interruptible service should typically be provided at a discount relative to firm capacity prices.*

Pipeline charges should promote efficient cross-border transactions, and must therefore avoid discrimination. We analyse a variety of different pricing methodologies: postage stamp, zonal, entry/exit and path-dependent approaches. We conclude that *no one approach automatically guarantees appropriate treatment of cross-border transactions*. For each methodology, we illustrate *specific examples* of potential discrimination against cross-border transactions. The examples are intended as guidance for the proper implementation of pipeline pricing, and as illustrations of the reasoning that may be applied in evaluating compliance with the Directive.

1.4. Balancing, Storage and Trading

We also analyse balancing services and prices. To avoid discrimination against third parties, *imbalance charges should reflect the actual costs of system balancing*. Such costs arise from *net imbalances* on the system, which are typically substantially less than the gross sum of individual imbalance positions of shippers.⁶

Outside of Europe monthly or daily balancing are the norm. However, TOs in some Member States have chosen to require hourly balancing. Before it is accepted that hourly balancing is an appropriate protocol, Member States should evaluate whether the TOs have retained sufficient system resources in the form of storage, pipeline capacity and linepack to allow them to avoid stringent balancing tolerances.

There should be consistency between the amount and type of system resources retained by the TOs for system balancing purposes, the stringency of the balancing

⁶ When many individual shippers have imbalances, some of these will typically cancel each other out. An aggregate system imbalance of just 1% or 2% may therefore arise from individual imbalances as large as 5% or 10%.

tolerances required, and the size of any imbalance penalties. TOs should have the burden to demonstrate that such consistency has been achieved.

Third parties should be allowed to aggregate and/or trade their imbalance positions. TOs should provide regular and timely information to each shipper as to the size of its imbalance position and the coincident linepack status of the system. *To facilitate short-term swaps, third parties should be allowed to “pool” imbalances and avoid penalties for off-setting gas flows.*

Non-discrimination requires that *incumbents provide third parties either access to storage assets or services that allow equal flexibility*, which we label “virtual storage”. Harmonisation may be required in some areas, which should if possible arise through the voluntary efforts of market participants and regulators. *Storage tariffs should not contain any element of monopoly profit.*

We supplement our analysis of pipeline services and their pricing with an assessment of the broader market context necessary for successful implementation of the Directive. Our analysis of pipeline services emphasises the importance of trading and trading mechanisms. We recommend that, to implement the Directive successfully, *ownership of physical assets should not be a pre-requisite to trading*. Traders and trading institutions are important components of a competitive gas market.

1.5. Security of Supply, Take-or-Pay and PSOs

Our analysis shows that markets tend naturally to enhance security of supply. Demand for security of supply from those consumers who value it most highly creates natural incentives for firms to provide it, while markets have a natural tendency to seek out diverse sources of supply. Experience in other markets confirms that security of supply concerns may safely be entrusted to markets, except in the most unusual circumstances. However, some concerns may justify government intervention. We recommend that the rationale for any government intervention should be stated transparently. Measures should be non-discriminatory and transparent, explicitly linked to stated goals, and chosen to minimise distortion to the competitive process.

Finally, we conclude that *the Directive’s criteria for take-or-pay derogations should be strictly applied*. Incumbents seeking such derogations must provide objective evidence of the serious economic or financial difficulties that would arise from providing open access. The process of granting derogations should be as transparent as possible, and any derogation that is granted should be reviewed on a regular basis, and ended as soon as possible. We see no economic justification for denying access in respect of take-or-pay contracts that are signed after the Directive was passed. International evidence suggests that take-or-pay contracts *cannot* be justified generically as necessary for security of supply. Rather, they can prevent the market from developing so as to provide its own security of supply. Take-or-pay derogations therefore impede efficiency and make little or no contribution to achieving the goals of the Directive.

1.6. Harmonisation

Our report recommends harmonisation in a number of areas, including: the definition of firm capacity rights; nomination procedures, gas allocation procedures and settlement mechanisms; rate-making methodology and asset valuation, when pipelines compete; design of charges (the fix/variable split); balancing rules and protocols.

Where possible such harmonisation should be promoted via voluntary industry action. The formation of an industry body to help develop European standards, perhaps in conjunction with the Gas Regulatory Forum, could be a useful way to proceed. However, such a body should reflect the views of all classes of market participants.

1.7. Next Steps

Our report suggests two sets of concrete measures to further the implementation of particular parts of its recommendations. These suggestions are in no way intended to be exhaustive. Rather, they focus on areas that require co-ordinated action by European market participants.

First, in relation to the choice of pricing methodology and its implications for cross-border transactions, we recommend the process summarised in Figure E1 above. Second, in relation to required harmonisation measures, we recommended the voluntary formation of an industry group, with extremely broad membership, to help determine European standards for natural gas, perhaps in conjunction with the Gas Regulatory Forum.

1.8. Structure of Report

The rest of this report is structured as follows. We briefly outline the current state of the European natural gas industry, describing the market history and structure, as well as the major cross-border flows that currently occur. We then discuss those aspects of the Gas Directive that are of the greatest significance in relation to open access and cross-border trade: non-discrimination, the creation of a competitive market, interconnection and interoperability, security of supply, the interpretation of negotiated access, and issues related to unbundling.

We proceed to apply the principles of the Directive to each of the most important elements or “building blocks” of open access. We first describe the services that should be made available to third parties: firm capacity rights, interruptible service, and “customised” services under appropriate circumstances. We examine how these services should be priced, addressing the determination of the appropriate total revenue, the design of charges for individual services, and the pricing of cross-border transactions. We then discuss a series of complementary issues: balancing rules and protocols, storage, trading mechanisms, security of supply, and take-or-pay contracts. Finally we summarise our recommendations concerning which elements of open access require harmonisation, and how such harmonisation should best be achieved, and briefly discuss some next steps towards implementation of our recommendations.

2. The European Gas Industry on the Eve of Liberalisation

2.1. Market Structure

The gas market in the European Union grew up relatively recently, by international standards. It emerged in the late 1960's with the development of the Dutch Groningen field, and in the 1970's and 80's with the further development of off-shore North Sea gas supplies. Major international oil and gas companies were largely responsible for the development of those fields, and together with European governments were primarily involved in the large investments in pipeline systems to deliver this gas to the U.K. and the Continent.

The major pipeline systems that were constructed, such as the British Gas system and the systems of Gaz de France, Gasunie, Distrigaz and SNAM, were primarily state-owned enterprises. Companies like Ruhrgas in Germany played similar roles to these state-owned enterprises despite being privately-owned. The British Gas system was privatised by the British government in 1986 as a regulated monopoly.

Additional upstream supplies from Algeria, Russia and Norway were provided by state-sponsored development projects. Norwegian exports were tightly controlled by the state-owned company Statoil and its partners Norsk Hydro and Saga.

The traditional contractual vehicles for gas supplies as the market developed were long-term, take-or-pay contracts with relatively rigid prices, or prices indexed to those for oil. These contracts were viewed as essential to underwrite the large investments in gas production and transportation required to develop the market.

In the early-1990's this highly nationalised and integrated gas transmission structure began to see the emergence of third-party entrants. The largest of these was Wingas, a joint venture of Wintershall and Gazprom. Wingas constructed the MIDAL pipeline from the North Sea to the middle of Germany to compete with Ruhrgas, followed by the STEGAL pipeline through Slovakia and the Czech Republic, which connects with MIDAL in Germany to bring Russian gas to both eastern and western Europe.

Other competitive market developments that set the stage for the implementation of the EU Gas Directive included the following transactions and projects:

- the 1990 contract between SEP (Dutch Electricity Producers) and Norwegian gas suppliers to supply power stations, and thus bypassing Gasunie; and a similar contract by Electrabel of Belgium bypassing Distrigaz;
- completion in 1998 of the UK-Continent interconnector pipeline, a joint-venture owned by nine separate parties;
- the initial operation of a physical and trading hub for gas at Zeebrugge, beginning in late 1999.

Thus, on the eve of the implementation of the Gas Directive, the European gas market consists of a mixture of physical and transactional infrastructure. The structures range from the nearly fully-liberalised and regulated market in the U.K., with the unbundling of the previously vertically-integrated British Gas system, relatively high spot gas liquidity and capacity booking by auction process, to structures that are still heavily dominated by vertically integrated monopolies and influenced by state-ownership .

2.2. Current Cross-border Flows and Existing Tariffs

Currently, the EU can meet around 60% of its gas consumption through indigenous production. The shortfall is made up by imports from Russia, Algeria and Norway. As Table 2 shows, the profile of production and consumption across Europe varies widely, requiring the importing of large quantities of gas as well as internal gas movements within and between Member States.

Table 2: Overview of Main EU Gas Supply Flows (Million tonnes of oil equivalent)

	A	B	DK	FIN	F	D	EL	IRE	I	L	N	P	E	S	UK	EU-15
Own Production [1]	1.4		7.4	.1	1.9	16.7	.0	1.6	17.3		63.5		.1		91.1	201.1
Extra -EU Imports																
Norway [2]	.3	5.0			10.0	17.4				4.9			2.3		.8	40.7
Former USSR [3]	4.6			3.2	10.0	28.7	.5		14.6							61.6
Algeria [4]		4.1			9.6				20.3			.8	8.9			43.7
Libya [5]													.9			.9
Total [6] Sum([2]-[5])	4.9	9.1		3.2	29.6	46.1	.5		34.9		4.9	.8	12.1		.8	146.9
Intra-EU Imports [7]	.3	4.9			4.1	19.8			1.7	.7	.8			.9		33.2
Total Imports [8] [6]+[7]	5.2	14.0		3.2	33.7	65.9	.5		36.6	.7	5.7	.8	12.1	.9	.8	180.1
Total Resources [9] [1]+[8]	6.6	14.0	7.4	3.3	35.6	82.6	.5	1.6	53.9	.7	69.2	.8	12.2	.9	91.9	381.2
Total Exports [10]			2.7			14.6					30.7				2.7	50.7
Gas Consumption [11] [9]-[10]	6.6	14.0	4.7	3.3	35.6	68.0	.5	1.6	53.9	.7	38.5	.8	12.2	.9	89.2	330.5

Source: Eurostat, January-December 1998.

A - Austria, B - Belgium, DK - Denmark, FIN - Finland, F - France, D - Germany, EL - Greece, IRE - Ireland, I - Italy, L - Luxembourg, N - Netherlands, P - Portugal, E - Spain, S - Sweden, UK - United Kingdom.

The major gas transit pipelines including the major cross-border pipeline connections in Europe are shown in Figure 1 overleaf. Austria, Belgium and Germany by virtue of their central geographical position have large quantities of gas passing across their territory. Germany, Italy, France, and Spain are considered to be of special interest and importance because of their gas demand and the relative lack of indigenous gas production. The United Kingdom is the largest European producer of gas. The Netherlands while producing slightly less gas than the UK, exports far more, mostly to Germany, but also to France, Italy and Belgium.

Figure 1: European Gas Transmission



Germany is the largest consumer and importer of gas in the EU. Over half of Germany's consumption is made up of gas from outside the EU. Its supply from the Netherlands constitutes the single largest internal cross-border flow.

While it is clear that there is substantial flow of gas across European state borders, the bulk of this flow is associated with bundled sales contracts under traditional long-term take-or-pay contracts. Respondents to our questionnaire survey (summarised in Appendix 3) generally indicated that unbundled, third-party cross-border transactions are currently relatively limited in scope. They are principally confined to the UK-Continent interconnector (with signs of a market in capacity emerging there), and to certain transactions associated with one-off, negotiated and "bundled" long-term contractual arrangements for delivered gas. Examples of the latter that were identified by respondents include:

- Norwegian gas that crosses France is contracted at the Spanish border;
- transactions on the Magreb-Europe pipeline;
- contracts for the delivery on the DONG (Danish) pipeline specifying the delivery of gas at the Swedish and German borders at fixed prices;
- a contract for the transportation of Algerian gas to Sicily and Centre-South Italy over TRANSMED;
- agreements between GdF and SNAM entailing the use of two regasification terminals (at Montoir in France and Panigaglia in Italy), completed by swaps of Nigerian gas for Russian and Algerian gas.

Appendix 1 compares the existing tariffs for gas transportation in those Member States for which we have been able to obtain information: the United Kingdom, the Netherlands, Germany (based on the draft "VV") and Spain.

3. Principles of the Gas Directive

This chapter elaborates on the interpretation and application of the general principles embodied in the Gas Directive. It identifies areas where harmonisation among Member States is essential to achieving the Directive's goals, while bearing in mind both the principle of subsidiarity and the desirability of achieving harmonisation through voluntary standards commonly agreed amongst market participants, rather than through legislation.

Among the principles underlying the Directive, those with the most significant implications for open access and cross-border trade include the principle of *non-discrimination*, the goal of establishing a *competitive natural gas market*, and the promotion of *interconnection and interoperability*. The Directive gives Member States the right to choose between systems of *regulated and negotiated third party access*, and contains important provisions on *unbundling* in vertically integrated undertakings.

3.1. Non-Discrimination

The Directive repeatedly invokes the principle of *non-discrimination*, applying it to areas including: Member States' authorisation procedures (Articles 3, 4 and 5); Transmission, Storage and LNG (Article 7); Distribution and Supply (Article 10); and Access to the System (Articles 14, 20). It is also implicit in the other principles identified above, since discrimination is incompatible with a competitive natural gas market, and creates barriers to interconnection and interoperability. The principle of non-discrimination affects many aspects of the Directive's implementation, and has special significance because of the structure of the natural gas industry in Europe.

In most Member States, transportation and distribution networks belong to vertically integrated undertakings. When such a network is part of a vertically integrated undertaking, it is explicitly forbidden to discriminate in favour of its related undertakings (Articles 7.2 and 10.2). The same prohibition applies also to storage and LNG undertakings (Article 7.2). In interpreting the Directive, it is necessary to determine the extent to which *non-discrimination requires such an entity to make available to entrants the range of services that is available to its related undertakings*. For example, such an entity will typically make interruptible service available to its affiliates, even if only on an *ad hoc* or case-by-case basis. The principle of non-discrimination would require an interruptible service of equal flexibility for entrants.

Access terms that are formally non-discriminatory, but whose economic effect is to unreasonably disadvantage certain classes of customers, are discriminatory in the economic sense. For example, suppose that transportation tariffs are distance-related, and that transportation charges rise with distance to an extent that does not reflect the additional costs involved. In a narrow sense the tariffs may not seem discriminatory, because the same distance-related formula applies to all market participants, including related undertakings of the transmission operator itself. However, such tariffs are discriminatory in an economic sense, because they effectively penalise more distant suppliers.

To respect the principle of non-discrimination, *tariffs should reflect costs in a broad sense*. Here and throughout this report, the concept of costs should be understood to encompass operating costs, congestion costs⁷ and the cost of capital. It is unreasonable to expect more than broad cost-reflectivity, since the complexity of gas transmission and distribution, and the presence of fixed and sunk costs, rule out the exact measurement and allocation of costs to individual transactions. For example, one common form of charging used by transportation and distribution networks is the postage-stamp tariff. A postage-stamp rate can never be exactly cost-reflective, since there will always be differences in the costs incurred in serving different customers. However, a postage-stamp rate may be a reasonable solution for certain systems. The key to identifying discrimination is whether the size of a postage-stamp area imposes unreasonably high charges on certain classes of customers relative to others.

Finally, the appropriate degree of concern with discriminatory behaviour is closely related to the extent of *unbundling*. When activities are highly separated, by “functional” unbundling or vertical separation of ownership, then discrimination becomes less likely. In those circumstances, when discrimination does occur, unbundling makes it easier for market participants to detect and to obtain redress. When unbundling is relatively weak, strong incentives for discrimination may remain, and discrimination will be harder to detect. Bearing these issues in mind, Member States may well choose to require more rigorous forms of unbundling than the obligations imposed by the Directive. In assessing compliance with the Directive, it is also appropriate to analyse more closely those discrimination claims concerning undertakings that have implemented the least unbundling.

3.2. Establishing a Competitive Market

The Directive explicitly cites the establishment of a *competitive natural gas market* as a fundamental objective (Whereas 3, Articles 3 and 23). The Directive also notes explicitly that its provisions should not prevent the full application of the rules on competition (Whereas 6), and requires Member States to take steps “to avoid any abuse of a dominant position, in particular to the detriment of consumers, and any predatory behaviour” (Article 22).

The principle of a competitive market has a number of significant implications. First, it *reinforces concerns over discrimination* in many areas. For example, in a fully competitive market transportation undertakings would have natural incentives to offer a wide variety of services, and to disclose information that could maximise system utilisation. Second, *firms in competitive markets can not expect to earn monopoly profits*,

⁷ “Congestion costs” represent the costs that arise due to the existence of congestion. For example, if congestion means that a customer must be supplied with more expensive gas from elsewhere in the system, or that an interruptible customer’s service must be interrupted, then these “opportunity costs” form part of the congestion costs.

which involve returns above the cost of capital.⁸ The prohibition on abuse of a dominant position therefore implies that tariffs should not allow a pipeline to expect more than a competitive return on investment. Third, *prices in competitive markets are necessarily cost-reflective* (except where distortions are necessary and sustainable to facilitate legitimate public-service obligations), because the possibility of entry rules out cross-subsidisation of activities. Fourth, competitive markets ensure efficient use of all system assets. In particular, they tend to *maximise usage of capacity* and to *foster efficient capacity expansion*. Fifth, effective competition often entails the creation of *trading institutions* such as hubs, spot and forward markets (for gas itself and for transportation capacity), trading instruments such as swaps and futures, and involves actors such as traders, brokers and load aggregators who facilitate trade and promote market liquidity. Although the Directive does not mandate particular trading instruments or institutions, their presence provides a useful benchmark for assessing the fulfilment of the competitive market objective.

3.3. Interconnection and Interoperability

The promotion of *interconnection and interoperability* of systems is inherent to the completion of the internal market, and deficiencies in this area form a significant obstacle to cross-border trade. The Directive confirms its importance explicitly (Whereas 8 and 15), and requires Member States to ensure interoperability (Article 5). This principle has significant implications for the *harmonisation of standards across systems and across national boundaries*.

Harmonisation

Experience in mature gas markets elsewhere suggests that *voluntary action* by industry participants can produce the required degree of harmonisation in a manner that is non-discriminatory and enhances competition. For example, regulators in the United States have encouraged an industry association, the Gas Industry Standards Board (“GISB”), to develop standards on behalf of the industry.⁹

Importantly, GISB has an extremely broad membership, including producers, transporters, distributors, end-users and service providers such as brokers, and its voting structure ensure that its standards represent a broad consensus across the industry. Such a collective harmonisation approach may be useful for industry participants in the EU gas market to ensure the smooth interoperability of its interconnected systems. It is essential that any industry body that promotes standards for the implementation of the Directive

⁸ The cost of capital is a fundamental concept in financial economics. It denotes the expected return on capital that investors require in order to invest funds in a project. In a competitive market, the cost of capital must be equal to the expected return that investors could earn on alternative investments with similar risks to the project in question. Here risk is understood in a specialised sense of “systemic risk”, which excludes project-specific risks such as unexpected delays in construction, and focuses instead on the extent to which the project’s success or failure is correlated with the success or failure of alternative investments.

⁹ Appendix 4 describes the work of GISB in more detail.

represent the interests and opinions of all market participants. Given the current stage of market development, *it is essential to ensure that the interests of new entrants are fully reflected*. Otherwise the danger exists that the incumbents produce an implementation that favours their own interests over the goals of the Directive.

The principles of interconnection and interoperability provide further support for the use of *cost-reflective tariffs*. In particular, interconnection and interoperability will suffer when competing pipelines impose different charges for economically equivalent services. Finally, while harmonisation is crucial to the completion of the internal market, it should not be used as an excuse for restrictive and anti-competitive practices. If, for example, pipelines in a number of Member States were to adopt *discriminatory balancing requirements*, their precedent would not provide a legitimate argument for requiring other countries to follow suit. Although it may be important to adopt common balancing rules, they must be chosen to respect all the aims of the Directive.

3.4. Negotiated Access

Article 14 of the Directive allows Member States to choose between *regulated and negotiated third party access*, while requiring both procedures to operate “in accordance with objective, transparent and non-discriminatory criteria”. Article 15 states that “the contracts for access to the system shall be negotiated with the relevant natural gas undertakings. Member States shall require natural gas undertakings to publish their main commercial conditions for the use of the system within the first year following implementation of this Directive and on an annual basis every year thereafter”.

It is important to distinguish between two broad interpretations of “negotiated access”. Under the first interpretation, the TO has *initial flexibility in designing the price and non-price terms of access*, subject of course to full compatibility with the Directive’s requirements. These may be negotiated between the TO and potential customers. Once the TO has determined the terms of access, *it must then publish them in sufficient detail to ensure transparency and non-discrimination, and apply the published terms in a consistent and objective fashion to all parties, including its own affiliates*. These define a set of “basic services” that are available to third parties without subsequent negotiation. Member States may choose to give the TO the right, subsequent to publication, to negotiate non-standard access terms for individual customers, on a case-by-case basis, and as a supplement to the provision of the “basic services”. However, such a right is balanced by rigorous safeguards against abuse. While the published terms may be changed from time to time, such changes must be objectively justified, and must be carried out in a timely and transparent manner.

The second interpretation of negotiated access is very different. It imagines that the TO is free to negotiate each contract on a case-by-case basis, in a *laissez-faire* manner and with few safeguards. In particular, the second interpretation omits the requirement to make available standard “basic services”. Negotiation would therefore entail a process of inquiring and awaiting responses concerning the availability, terms and cost of transmission services.

Until gas markets are mature, the second of these interpretations would be highly counter-productive. Without the safeguards envisaged under the first interpretation above, negotiations are unlikely to “operate in accordance with objective, transparent and non-discriminatory criteria”, as required by Article 14 of the Directive. Until markets are mature, implementation of negotiated access in such a laissez-faire manner is also likely to lead to breaches of other provisions of the Directive, and of general competition law. The absence of proper safeguards would facilitate abuse of a dominant position by incumbent TOs to discriminate against entrants, and would prevent the creation of a unified, competitive natural gas market in Europe.

Without rigorous safeguards, case-by-case negotiations could easily lead to discrimination against third parties. In particular, discrimination occurs if affiliates of TOs can use the transmission system on short notice *without* having to bargain for the particular terms of service. Therefore, unless third parties have similar opportunities through the provision of standard services as described above, rigorous unbundling will be required to ensure that affiliates are similarly burdened. Moreover, the delays involved in bargaining can prevent short-term transactions that are essential to market development. Negotiations also open the door to the abuse of commercially sensitive information by TOs, who in the process acquire information about the locations of their competitors’ customers.¹⁰ Finally, bargaining in immature markets will result in higher transmission prices for those third parties who have weaker leverage with TOs. This violates the principles of discrimination and cost-reflective rates, which imply that the same prices should apply to all customers who impose the same costs on the system. One of the major concerns raised in industry consultations was that negotiated access would be interpreted as allowing incumbents to engage in case-by-case negotiation, leading to discrimination against entrants for reasons given above.

With regard to the publication requirement in Article 15, the “main commercial conditions” of access should be interpreted broadly. A third party seeking access to the system should be able to determine from the published information the terms and price that will apply to the service it requests.¹¹

Finally, we note that the discretion and flexibility allowed to system operators under negotiated access, whatever its advantages, necessarily increases the likelihood of abuse.

¹⁰ Such abuse is of course incompatible with the Directive. We discuss below how to discourage the abuse of commercially sensitive information by vertically-integrated pipelines.

¹¹ After privatisation British Gas was subject to a similar requirement. In early years however it published no more than a short set of “examples” of tariffs that might apply to a few hypothetical transactions. The Monopolies and Mergers Commission looked at the examples made available by British Gas and concluded, “we do not think the information made available by BG provides sufficient guidance to prospective users...We believe that BG’s failure to provide adequate information is attributable to the monopoly situation, and that this failure will make it difficult for third-party suppliers to estimate transmission costs and negotiate contracts with customers.” The Monopolies and Mergers Commission, *Gas: A report on the matter of the existence or possible existence of a monopoly situation in relation to the supply in Great Britain of gas through pipes to persons other than tariff customers*, (October 1988), para. 8.83 at 108.

It is therefore essential for a Member State that chooses negotiated access to create a suitable regulatory authority that proactively monitors the behaviour of system operators on a continuous basis, and is armed with significant powers to investigate and penalise abuse. Experience in other markets demonstrates that the alternative “passive” approach of acting only in response to third party complaints is inadequate to prevent abuse.

3.5. Unbundling

The Directive contains a number of safeguards against abuse by vertically integrated undertakings. Such undertakings are required to keep “unbundled accounts” (Article 13). Transmission and distribution firms are forbidden from using commercially sensitive information gained in the role of system operator in the context of sales or purchases of natural gas (Articles 8 and 11).

Experience in the early stages of the liberalisation of the UK gas market demonstrates that *such provisions are effective only when accompanied by strong regulatory oversight*.¹² Without such oversight, affiliates can acquire unique information allowing them to negotiate and sign new contracts before competitors learn that the requisite capacity is available. For example, financial regulators are typically armed with effective powers to demand information, and to impose punishments for violations of information-sharing rules.

The experience of British Gas suggests *enforcement of “Chinese Walls” is greatly facilitated if a TO is established as a separate business unit with separate physical premises from its affiliate*. Privatised in 1986, British Gas was obligated to provide access under a “negotiated access” regime up through the end of 1992. In 1988, the Monopolies and Mergers Commission heard complaints that, among other abuses, British Gas had demanded commercially sensitive information as a precondition for negotiation. In 1993, the MMC summarised its previous findings as follows:

The 1988 MMC report found that BG was practising extensive discrimination. BG’s contracts with nontariff customers were confidential, and prices were individually negotiated. The MMC found that this operated against the public interest...*BG was able selectively to undercut any competing suppliers because it related its nontariff prices to the prices of the alternative supplies of gas or gas substitutes available to the particular customer.*

In fact British Gas adopted a standard policy of requiring that both the potential supplier and customer be identified.¹³ This would of course enable them to approach the

¹² This problem was identified by competition authorities in the United Kingdom with respect to British Gas. A full discussion can be found in P.R. Carpenter and C. Lapuerta, “A Critique of Light-Handed Regulation: The Case of British Gas”, in the *Northwestern Journal of International Law and Business*, Spring 1999, Vol. 19, Number 3, pp. 479-497.

¹³ At least one of the respondents to our questionnaire described recent instances of similar behaviour by incumbents in Europe.

potential customer and undercut whatever price was being offered by their competitor. They could also punish the supplier in future dealings.

The MMC concluded that:¹⁴

BG's failure to provide adequate information on the costs of common carriage, its ability to use information obtained when negotiating common carriage terms to identify potential customers of competing suppliers and the potential source of gas, and its position as a dominant purchaser of gas, may all be expected to act against the public interest by deterring new entry into the market.

In 1993, the MMC revisited the regulatory history of British Gas in a new dispute over transportation charges. By then, a regulated access regime had been installed and the first steps toward separation of the British Gas transportation network had begun. This process first involved the creation of a separate subsidiary with separate premises, and eventually the “de-merger” of the British Gas sales and transportation businesses in 1997. Reviewing the history of abuse under negotiated access, the MMC noted: “it was by no means clear either that, if the transportation business was only a unit within the BG UK gas supply business, that the necessary ‘Chinese walls’ between the transportation and trading arms could be erected”.¹⁵

Although not explicitly required by the Directive, we conclude that the creation of separate subsidiaries with separate business premises will help safeguard the Directive's goals of preventing TOs from abusing commercially sensitive information.

¹⁴ *Ibid* 1.4, p.1.

¹⁵ Monopolies and Mergers Commission, Gas and British Gas plc – Volume 2 of reports under the Gas and Fair Trading Acts” (September 1993), p. 15.

4. Required Services

4.1. Capacity Rights

To promote competition and ensure non-discrimination, *tradable spare firm capacity rights must be made available to all pipeline users*. Experience in other markets demonstrates that firm capacity rights are a prerequisite to the development of competition. Customers are naturally unwilling to sign contracts without guarantees that the gas they purchase will be delivered. Such guarantees are therefore necessary for all third party trades whose time frame extends beyond the very short term.

Incumbents in most Member States currently provide consumers with firm gas supplies, which implicitly involves the provision of firm transportation capacity. Moreover, the Directive implicitly recognises their right to do so, by permitting denial of access on the basis of lack of capacity (Article 17). The principle of non-discrimination therefore requires that spare capacity be made available to all users on a firm basis. Similarly, since vertically-integrated incumbents are free to sell capacity not required for use by their affiliates, the principle of non-discrimination requires that third parties be free to do the same by trading their firm capacity on a secondary market.

We believe that it will be generally practical to seek to reallocate existing capacity rights under the Directive only under relatively limited circumstances. Existing allocations of capacity should not be allowed to create a situation where frequent denial of access occurs in the absence of genuine physical congestion. Our proposals in section 5.2 below concerning the provision of interruptible service should help prevent such denials from creating significant problems. If they prove ineffective then it may be desirable to impose “use-or-lose” requirements on existing capacity holders. Moreover, regulatory authorities should examine closely any recent long-term contracts that may have the purpose of preventing the creation of spare capacity.

However, the allocation of *spare capacity* is of the utmost importance. Spare capacity includes capacity that becomes available as contracts expire, or customers switch away from the incumbent. Under no circumstances should existing capacity holders enjoy preferential treatment, such as automatic renewal rights or a “right of first refusal” to renew contracts.

Allocation Mechanism

Various mechanisms can be used to issue rights to available pipeline capacity, including “first come, first served” policies, lotteries, “beauty contests” and auctions of various types. The attractiveness of these options from the perspectives of efficiency, non-discrimination and fostering competition depends on prevailing market conditions.¹⁶

¹⁶ Under certain circumstances the choice of mechanism is of little significance. Specifically, an efficient allocation will generally be achieved if capacity is not scarce. In these circumstances, the Footnote continues on next page.

If capacity is scarce and no competing pipeline exists, then there is danger that existing allocations may be inefficient and/or discriminatory. The existence of a *liquid secondary market* in capacity rights, as discussed below, can help to make the final allocation of capacity efficient, but cannot prevent discrimination in the pricing of capacity, or solve problems of market power in the market for capacity. In these circumstances the method used to allocate capacity rights is therefore of the greatest importance.

We proceed to analyse “first-come, first-served”, “beauty contests”, lotteries and auctions for allocating scarce capacity. Each of these methods has its own advantages and disadvantages, whose weights vary according to specific market conditions. We recommend against the use of “beauty contests” at any time, and against “first-come, first-served” during the early stages of market development. We favour the use of auctions rather than lotteries, provided that rigorous safeguards are in place to prevent abuse. Once markets are fully developed, any of these methods except for “beauty contests” can be considered.

“First-come, first-served”

In the early stages of market development, “first-come, first-served” is likely to discriminate in favour of incumbents, whose market presence and knowledge give them superior abilities to occupy the head of the queue initially. However, after the diversity of players has increased and a competitive structure has been realised, there is no reason to expect that any one group of participants would benefit from “first-come, first-served”. Of course, it is critical that the potentially discriminatory impact of “first-come, first-served” is not extended inadvertently by discriminatory provisions such as “right of first refusal” provisions.

“Beauty contest”

A “beauty contest” (where the allocation of available capacity is determined by the application of various subjective and objective criteria) risks discrimination, or the appearance of discrimination, because of the high degree of discretion involved in setting criteria and evaluating applications. It is also likely to be time-consuming, bureaucratic, non-transparent and subject to political influence that could give rise to improper market distortions. These flaws would not seem to decrease as markets develop.

Lotteries

The allocation of spare capacity rights by lottery is non-discriminatory, and leads to an efficient allocation provided that liquid secondary markets exist. Moreover, it is likely to promote the development of such markets, precisely because of the likely inefficiency

goals of the Directive require only that pricing of capacity is competitive and non-discriminatory. However, given expected growth in natural gas consumption in Europe, a situation of scarce capacity is likely to be the norm. The existence of effective competition between pipelines can also ensure efficient and non-discriminatory allocation.

of the initial allocation. However, it has the potential disadvantage of distributing rents in an arbitrary fashion, and creates an artificial incentive for entry.

Auctions

Under certain circumstances, auctions can better achieve an efficient initial allocation of spare capacity than the other mechanisms discussed. High bids in auctions can be expected to correspond to high valuations by the bidders, so that the winners tend to be those parties who value the capacity rights most highly.

However, under an auction system, and in the absence of supplementary regulatory provision, the pipeline owner would receive the rents arising from scarce capacity, and might therefore have a disincentive for efficient capacity expansion. More generally, even where capacity expansion is not at issue, it is quite possible for the total revenue from the auction to be so great as to create excess profits for the pipeline owner. A corrective mechanism is therefore needed both to ensure efficient expansion and to prevent excess profits. One solution is to require the pipeline owner to set aside any excess profits arising from the auction into a separate fund. Proceeds in the fund would be applied to the costs of future capacity expansion.¹⁷

Auctions and vertically-integrated undertakings

Auctions have an inherent potential for discrimination when conducted by vertically-integrated undertakings. If a TO's marketing affiliate is allowed to participate in the auction, then the integrated undertaking will have an inherent advantage in the bidding. Other market participants will be deterred in their bids by the fear of submitting an excessive bid. For the integrated undertaking, the bid will constitute simply a transfer payment from one affiliate to another, and have no net economic impact. The only risk of a high bid is the possibility of foregoing the revenues that the second-highest bidder might offer. If the second-highest bid is exogenous to the auction, as one might expect in competitive markets, then the incumbent's marketing affiliate will effectively benefit from a cap on its exposure from submitting an excessive bid. Other market participants face no inherent ceiling on their exposure from high bids.

In order to prevent such abuse, which is at odds with the Directive and infringes EU competition law (Article 82 EC), we recommend that vertically-integrated undertakings be allowed to allocate scarce capacity in auctions *only if the auction mechanism is rigorously designed to prevent excessive bidding by the pipeline's affiliate*.

¹⁷ Auctions may also have the opposite effect of creating "stranded costs", if the revenues arising from the auction are insufficient to allow fixed cost recovery. In some cases this may be a temporary phenomenon related to low initial utilisation. However, in other cases it may be reasonable to infer that fixed cost recovery will not be possible without some supplementary mechanism. Where stranded cost recovery is a legitimate goal, it should be achieved through transparent and non-discriminatory mechanisms that minimise distortions to the competitive process. One such mechanism would be the addition of a floor price to the auction

Appendix 5 presents one such mechanism, a “modified “n+1”-bid. The mechanism is most easily illustrated by an example. Imagine that there are five units available at auction. Under the mechanism’s rules, the incumbent is allowed to bid for no more than four of the five units, while entrants bid for as few or many as they wish. The auction allocates units to the highest bidder, and all bidders pay the owner a price per unit which is equal to the *sixth highest bid*.¹⁸ However, the incumbent’s affiliate is required to make an additional payment: the difference between its winning bids and the sixth bid is to be placed in a dedicated, “ring-fenced” fund that can be used to help pay for PSOs or fund capacity expansion. As a result, *the incumbent effectively “pays as bid”*, and therefore has a disincentive to “hoarding” capacity.

Liquid Secondary Markets

Lotteries and first-come, first-served procedures may comply with the Directive’s goal of non-discrimination, but alone they do not ensure an efficient initial allocation of capacity rights. The goal of efficiency favours the *establishment of a secondary market in capacity rights*. The value of capacity rights to potential users naturally varies over time. With a liquid secondary market, the parties who value capacity rights the most at any particular time period will purchase them. In addition, the existence of a secondary market can stimulate activity in the primary market by reducing the risk of purchasing capacity rights. Market participants will know that they can easily dispose of capacity rights if their business prospects do not develop as hoped. Finally, the secondary market can facilitate the equivalent of bilateral “swaps” without the need for buyers and sellers to contact each other and negotiate separate contracts on a case-by-case basis.

An effective secondary market for capacity rights therefore renders the initial allocation of rights to spare capacity and the distribution of prior contractual rights relatively unimportant from an efficiency perspective, eliminating the key disadvantage of lotteries and “first-come, first served” policies. Under any such policies, capacity rights are sold subject to a price cap that prevents the pipeline owner from earning excess profits.¹⁹ If the cap binds, so that the price is below the market-clearing price, then demand will exceed supply and the rights are distributed by the allocation mechanism. Such policies therefore rely on secondary markets to allocate capacity efficiently and to provide incentives for efficient pipeline expansion. High prices for capacity in secondary markets signal scarcity, implying that new capacity will enjoy high utilisation. TOs will therefore naturally choose to expand those pipes where capacity is most scarce. Moreover the price cap removes any potential incentive of the TO to engage in monopolistic behaviour by restricting expansion, since any scarcity rents go not to the TO but to other market participants in non-discriminatory fashion.

¹⁸ This rule, or close variants on it, are standard in many auctions. We understand that PreussenElektra recently used a similar method to auction capacity rights on its international interconnectors.

¹⁹ We discuss the construction of appropriate price caps in section 5.2 below.

It follows that firm capacity rights should be tradable, and the necessary protocols should be simplified and harmonised so as to maximise liquidity in secondary markets. The existence of a liquid secondary market in capacity rights is a feature of competitive natural gas markets, and will foster competition and cross-border trade.

There should be no requirement to pre-notify or obtain approval from the pipeline operator for capacity trades. Such requirements are a significant disincentive to trade. As well as creating an unnecessary procedural burden, they allow the pipeline operator to obtain commercially sensitive information that may be abused by its related undertaking. In particular, an entrant who wishes to serve a customer previously contracted to the operator's marketing division should be able to obtain the necessary capacity without the operator learning of the potential loss of a customer.

Ensuring the proper functioning of the secondary market is not trivial. Specifically, the initial allocation should foster liquidity in the secondary market and avoid the potential for market dominance. Dominance of the secondary market can be avoided by putting a suitable cap on the amount of spare capacity that any single party is allowed to hold. A number of regulators in the United States have attempted to impose price caps in the secondary market, but this is unsatisfactory as it gives rise to a tertiary "grey market" where contractual devices are used to circumvent the price caps. Such devices impose high transactions costs and lead to illiquidity in the market. Various other approaches have been used and are currently under consideration in the United States.

Capacity Availability

The Directive permits denial of access on the basis of lack of capacity (Article 17). By implication, this requires pipeline owners to provide access whenever capacity is available. The requirement to provide firm capacity rights must therefore encompass an obligation to *release spare firm capacity whenever it becomes available*. This obligation also arises as a consequence of the principle of non-discrimination. Vertically integrated pipeline owners will make spare firm capacity available to their affiliates, and should therefore be required to make it available to all users.

An essential component of this obligation relates to the *publication of information on the extent of current and future allocations of firm capacity rights on each system*. For example, suppose that a large contract will shortly come to an end, making new capacity available on a pipeline. Unless unbundling is extremely effective, knowledge of this fact is likely to spread from the TO to its marketing affiliate. In this case non-discrimination requires that the information be made public. Publication is also consistent with Article 17, which requires information to justify denials of access, and with the provisions in Articles 7 and 10 on providing sufficient information to transmission and distribution undertakings for the secure and efficient use of the interconnected system.

Even if unbundling prevents the abuse of confidential information, publication is required by a different goal of the Directive: *promoting efficiency*. Publication of information on the extent of current and future allocations of firm capacity rights will enhance a TO's ability to utilise its capacity fully. Moreover, the goal of a *competitive*

market is also satisfied by the publication of such information, since network industries in competitive markets would automatically have incentives to disclose such information.

Disclosure should take place in such a way as to *avoid revealing commercially sensitive information*, as required by Articles 8 and 11. This can be achieved by restricting the information to aggregate figures describing available capacity. For example, a manufacturer that intends to increase the size of its operations at a particular plant, and therefore books increased future capacity, may not wish to give its competitors advance warning of its expansion plans. The pipeline should therefore provide only data of the form “for the month of March ’01, currently allocated firm capacity is 0.9 MCM”. The identity of the capacity holders need not be disclosed.

Current practice in the United Kingdom provides an example of good practice in this area. The pipeline owner, Transco, makes publicly available detailed information concerning capacity availability, including an annual “Ten Year Statement” giving its forecasts of capacity expansion over the next decade. It also provides third parties with a computer programme that enables them to model capacity and forecast constraints.

From time to time disputes will arise over the definition and measurement of spare capacity. Although these disputes are difficult to resolve, *certain principles can usefully be applied*. First, the pipeline should disclose detailed data describing historical utilisation. Historical utilisation provides a benchmark for estimating current and future utilisation, and hence for forecasting the *availability of spare capacity*. Such benchmarks help third parties and regulators notice any attempt to exaggerate expected utilisation. Pipelines should be required to provide objective justification if forecast utilisation differs significantly from historical patterns. Where this may involve commercially sensitive information, it should be revealed only to the regulator or dispute settlement authority, but in other cases, or where the authorities do not accept that it is commercially sensitive, it should be made available publicly.

A second principle concerns a situation that can be anticipated as typical in the first few years of liberalisation: an incumbent’s customer chooses to switch suppliers. The customer’s total consumption of gas is not expected to increase. All else being equal, “spare” capacity is created by the decision to switch away from the incumbent. In these circumstances it should therefore be considered automatic that the pipeline provides the required capacity, with exceptions allowed only under extraordinary circumstances, and requiring detailed supporting evidence by the pipeline.

A third principle is simply the obligation discussed above to publish information on available capacity. The availability of this information will make disputes less frequent and easier to resolve. To minimise the potential for disputes, the information published by the pipeline owner should include technical data, such as the availability of compressor capacity, that would enable third parties to confirm objectively its capacity forecasts.

At least as important as these principles are two measures that should substantially reduce the need for disputes. First, Member States should make full use of Article 17(2) of the Directive to *require pipelines that deny access on the basis of lack of capacity to make the necessary enhancements* provided they are economical or the customer is

willing to pay for them. Second, pipelines should be required to *provide interruptible service*. We discuss this requirement in detail below, and explain how it can reduce the need for disputes.

Harmonisation

Harmonising the nature of firm capacity rights across systems and countries is required, at least during the “transition period”, to promote interconnection, interoperability and a competitive internal market. For example, if rights are sold for different lengths of time on different pipes, then it may be difficult to contract to provide gas across them. Suppose that a contract requires transport across two pipes, one of which makes capacity available for periods of two years, the other for periods of three years. A four-year gas purchase contract would require the purchase of redundant pipeline capacity: four years capacity on one pipeline, and six years on the other. As discussed above, such harmonisation may be achieved by market participants agreeing on voluntary standards, provided those standards are non-discriminatory and promote competition.

Once markets have matured, an alternative, market-oriented approach may provide a better solution to such problems. If *capacity rights can be “repackaged”* by third parties and then resold on the secondary market, then the menu of available rights will itself be determined by the market. In our example, a broker might purchase six years capacity, and then sell the first four years to the supplier in question, while finding another purchaser for the last two years. The pipeline owner should therefore be required to accept such repackaging.

Problems of this nature can also be mitigated by ensuring that *within each system some agreed fraction of spare capacity in each pipeline is reserved for a firm capacity service of no more than one year in duration*. The remainder can be subject to multi-year contracts. Industry participants should decide on an appropriate split between annual and multi-year capacity rights. Ensuring the availability of one-year firm capacity rights will also further compliance with two principles of the Directive: non-discrimination and the development of a competitive market. In the early stages of liberalisation, entrants would be placed at a distinct disadvantage if capacity were offered exclusively for long-term periods such as twenty years. Experience in other markets has shown that many industrial customers do not like to purchase gas for periods of more than one year at a time. If third parties can only purchase transportation rights in twenty-year blocks, then successful entry would entail the risk of securing twenty successive one-year supply contracts with a sufficient number of industrial customers. This risk could deter an entrant from the market, even if the entrant could serve a specific customer’s one-year needs more efficiently than an incumbent. The result would be discriminatory. By deterring entry and by thwarting an increased diversity of market participants, such a practice would also contradict the Directive’s goals of developing a competitive market. Once markets mature, however, the availability of one-year capacity rights might not be a material issue. In a mature market, a pipeline owner might offer twenty-year capacity rights exclusively without impeding competition, if liquid secondary markets ensured that participants could trade unneeded capacity at efficient prices and with minimal transaction costs.

To foster greater flexibility in the use and trading of capacity rights, it is also important that they are defined in a way that provides flexibility in the definition of entry and exit points. Without such flexibility, the secondary market may suffer from illiquidity because, for example, a capacity right that entails delivery to a particular point cannot substitute for a capacity right to deliver to a different but geographically close location. Incumbent affiliates are likely to enjoy such flexibility, and its absence is therefore incompatible with both the principles of non-discrimination and of fostering competitive markets.

The principles of interconnection, interoperability, and a competitive internal market also require the *harmonisation of a variety of more technical procedures*, including *nomination procedures, gas allocation procedures and settlement mechanisms*. Such harmonisation is necessary to remove significant obstacles to cross-border trade. It has been achieved in mature gas markets elsewhere, through industry-led standards endorsed by regulatory authorities.²⁰ In the absence of perfect harmonisation, disputes may arise between interconnected systems that have incompatible definitions of capacity rights. Although interconnected systems may acknowledge the need for harmonisation, each may prefer that harmonisation be achieved by forcing conformity upon the others. Resolving such cases requires reference to the economic principles of efficiency and the facilitation of competition and liquidity. Evidence as to the most desirable parameters of firm capacity is best derived from analysis of developed gas markets in other countries, and by consulting a broad range of market participants who have financial interests in efficient and competitive markets.

Conclusions and Recommendations

1. TOs should ensure that spare capacity rights are made available to all users on a firm basis, with full rights to the use or remarketing of the associated capacity.
2. Existing capacity rights should be respected. However, “spare” capacity rights include rights that become available as contracts expire, or customers switch away from the incumbent. Allocation of rights should be non-discriminatory, and in particular existing rights holders should not receive preferential treatment.
3. If (contrary to our recommendations below) an “on-demand” interruptible service is not available, then it may be desirable to impose “use-or-lose” requirements on existing capacity holders.
4. Initially, we recommend auctions for the allocation of spare firm capacity among market participants. However, rigorous safeguards are required to prevent abuse by vertically-integrated pipeline owners.
5. After markets have developed, allocation by “first-come, first-served” or lotteries can be considered. However, we recommend against “beauty contests”.

²⁰ See Appendix 4 for a description of the role of the North American industry association GISB.

6. Firm capacity rights should be tradable with no requirements for advance notification or consent from the TO.
7. TOs should be required to publish timely and detailed information on the existing and projected availability of spare firm capacity on their systems, while protecting the identity of capacity rights holders.
8. Some agreed fraction of spare capacity in each pipeline should be reserved for a firm capacity service of no more than one year in duration. The remainder can be subject to multi-year contracts. Industry participants should decide on an appropriate split between annual and multi-year capacity rights.
9. The definition of capacity rights should allow for flexibility in the choice of receipt and delivery points.
10. Industry participants should also harmonise the definition of firm capacity rights, as well as nomination, allocation and settlement procedures.

4.2. Interruptible or “On-Demand” Service

Utilisation of booked firm capacity varies significantly over time, reflecting fluctuations in the demand and supply of gas. Some of these fluctuations are difficult to predict, and consequently, a significant part of booked firm capacity may be unused at any particular moment. The existence of unused capacity in significant but unpredictable quantities makes it efficient to offer *short-term interruptible* (“on-demand”) service in addition to firm capacity rights. Experience shows that such services are attractive to pipeline users, and lead to increased capacity utilisation and market liquidity.

Short-term interruptible service promotes competition in several ways. First, it facilitates the development of a spot market in natural gas. Without interruptible service, market participants would be obliged to acquire firm capacity rights for spot transactions. Until capacity markets are well developed, it can be difficult to acquire capacity quickly on a short-run basis. Short-term interruptible service can therefore be essential for spot market development, as appears to have been the case in gas markets outside the European Union.

Second, the availability of capacity on short notice reduces potential incentives to hoard spare capacity for anti-competitive purposes. In the absence of a short-term interruptible service, hoarding capacity can prevent other parties from obtaining access. Interruptible service allows participants to use the system even if capacity is hoarded, motivating the release of spare capacity on secondary markets and fostering the development of liquidity.

Third, as mentioned above, the provision of interruptible service can mitigate the impact of disputes over the measurement of available firm capacity. For example, a dispute may arise when a pipeline refuses access on the grounds that all current capacity is needed to meet the peak demand of existing customers. The party seeking access may deny this, and resolving the issue is complex: the two sides will put forward different estimates of available capacity, based on different assumptions as to likely peak demand. They may also have different views as to what probability of curtailment is acceptable: the incumbent may seek to “gold-plate”, insisting that it cannot provide firm access to an entrant unless it can be 100% certain that this will not entail curtailment, while the entrant may suggest that some small but non-zero risk is acceptable. The availability of interruptible service can minimise such disputes. If the party seeking access is persuaded that there is sufficient spare capacity in the pipeline, then it will be content to purchase interruptible rather than firm capacity because it may not anticipate significant interruptions.

This form of dispute avoidance can be promoted by ensuring that the grounds for interruption are transparent, objective and capable of verification by all parties. It may also be desirable to ensure that parties for whom interruption is a greater concern should be able to obtain priority over parties who are less concerned, by providing a number of interruptible services with different probabilities of interruption. Purchasers of the higher probability service would pay less, but would be chosen for interruption ahead of

purchasers of the lower probability service. Such arrangements exist in mature gas and electricity markets.

Because of the value created by interruptible and other short-term services, we would expect them to be readily provided by owners of capacity in a competitive market. Consequently, *in fully mature gas markets, where firm capacity rights are widely available and traded on a liquid secondary market, it is not necessary to mandate the provision of interruptible service.* Third parties who purchase firm capacity have natural incentives to offer short-term services that are close substitutes for interruptible service. Consequently, where there is a liquid secondary market in capacity rights, competition with such third parties means that the TO has no reason to withhold interruptible service, and has a natural incentive to offer it at market rates.

However, to implement the objectives of the Directive, *pipeline owners should be required to provide interruptible service in the transition to fully competitive markets.* Until a liquid secondary market in capacity exists, pipelines may have incentives to refuse interruptible service, impeding the goals of the Directive. As noted above, the availability of interruptible service is important for the development of competitive gas markets.

The obligation to make available short-term interruptible service during this transitional phase follows also from the principle of non-discrimination. Short-term interruptible service is usually implicitly available to incumbents. If the related undertaking of a pipeline owner has an unpredicted need for capacity on a short-term basis, it is clear that the pipeline will provide it if available, subject to its other commitments. Where this is the case, and until a liquid secondary market ensures that equivalent services are available to other parties, the principle of non-discrimination requires that the pipeline provide the same interruptible service to others.

If the pipeline has implemented full and effective functional unbundling, then it might in theory be possible to refuse interruptible service to all parties, including its related undertakings, on a non-discriminatory basis. However, there is no reason for a pipeline to withhold interruptible service, which contributes significantly to efficient utilisation. Moreover, denying access to interruptible service would contravene Article 17 of the Directive, which implicitly requires that *spare* capacity be made available to others.

Allocation and Pricing of Interruptible Service

Since interruptible service can be provided competitively by holders of capacity rights in mature gas markets, there is no need to regulate its price. However, in the transition phase a pipeline could earn monopoly profits from unregulated tariffs for interruptible service. The price therefore should be fixed or capped by regulators. The optimal price for interruptible service lies somewhere between the cost of its provision, which is equal to the variable cost imposed, and the price of firm capacity. In principle the exact optimal price can be determined by applying the economic principles of “Ramsey pricing”.²¹

²¹ “Ramsey pricing” is a method of determining prices in situations where marginal cost pricing is impractical due to the need to recover fixed costs (or more generally, to raise funds above marginal Footnote continues on next page.

However, in practice this is ruled out by informational requirements. Instead, it is logical to allow the pipeline freedom to set the price, subject to two conditions: a price cap, and a revenue sharing mechanism that allocates the vast majority of the profit from selling interruptible service to the holders of firm capacity. In the United States, pipeline operators are generally required to credit 90% of revenues from interruptible service to holders of firm capacity.

The price cap acts as a safeguard against abusive pricing. Since interruptible customers do not place expansion demands on the pipeline, interruptible capacity should be priced at a discount to firm capacity. *The revenue crediting mechanism avoids over-collection by the pipeline, and channels the interruptible service profits to the firm capacity holders*, while leaving the pipeline some financial incentive to provide interruptible service. Financial incentives seem necessary because the informational asymmetry makes it difficult to determine whether or not a pipeline is actually making available all unutilised capacity. The revenue crediting mechanism has the added attraction of providing firm capacity holders with an incentive to ensure that the TO provides interruptible service.

The revenue crediting mechanism also fulfils another essential function: preventing discrimination in the pricing of interruptible service. Suppose that the pipeline charges a price higher than variable cost to all users, including its own affiliate. To other users, the cost of the service is the price paid. For the affiliate however that price represents merely a transfer. Such transfer payments frequently arise between related undertakings, and accountants may allocate fixed overhead and capital costs to such transactions, but from an economic perspective the only cost to the consolidated company of using the spare capacity is the short-run variable cost. In this situation the cost of using interruptible service is clearly lower for the company that owns the pipeline and its related undertakings than for third parties, contravening the Directive's principle of non-discrimination. However, the revenue crediting mechanism ensures that the price charged by the pipeline to its affiliate represents more than just a transfer. The revenue crediting mechanism can allocate the majority of the fixed cost recovery to firm capacity holders on a non-discriminatory basis.

An effective short-term interruptible service requires that information on available capacity be made publicly available on a regular basis. The same points made above in relation to firm capacity rights apply here. When incumbents possess the information, which is likely to be the more usual case, the obligation to disclose follows from the principle of non-discrimination. It is also consistent with Article 17 (information to justify denials of access), and with provisions in Articles 7 and 10 (sufficient information to transmission and distribution undertakings for the secure and efficient use of the interconnected system). Again, it is crucial that disclosure should take place in such a way

cost, *e.g.*, in the theory of optimal taxation, where it was first applied). Under Ramsey pricing, fixed costs are recovered with minimal economic distortion, by setting price-cost mark-ups that are highest on those products or services for which demand is the most inelastic.

as to *avoid revealing commercially sensitive information*, and this can be achieved by restricting the information to aggregate figures describing available capacity.

Conclusions and Recommendations

1. During the transition to developed gas markets, TOs should be required to offer a short-term interruptible (“on-demand”) service.
2. The price for interruptible service should be capped at the price of firm service on a 100% load-factor basis.
3. Interruptible service can be priced above short-term variable cost. However, if the price is significantly above short-term variable cost then the vast majority of the operating profit earned from such service should be returned to holders of firm capacity rights by some form of revenue crediting mechanism.
4. For interruptible service to be effective, TOs should publish timely and detailed information about the use of the system and its capacity.
5. Industry participants should agree standards for the terms of interruptible service.

4.3. The Flexibility to Negotiate “Customised Services”

We view firm capacity entitlements and “on-demand” interruptible service as essential ingredients for the development of efficient natural gas markets. We therefore focus on the pricing of these services in the next section. However, the principles of the Directive contemplate some flexibility by sanctioning “negotiated access” regimes. Such flexibility can involve the provision of a wider range of services than fixed capacity and “on demand” interruptible service. Moreover, the provision of a wider range of services is consistent with the Directive’s principles of efficiency and fostering the creation of a single internal market. We review the scope for such flexibility and conclude that it can be an important source of efficiency enhancements, but that *negotiations with individual customers must be surrounded with rigorous safeguards* until *after* gas markets have developed substantially. In the early stages of a market’s development, negotiations without proper safeguards open the door for discrimination and delays that can prevent the development of vital short-term markets in both capacity and gas supplies.

Negotiations in Recently Liberalised Markets

As discussed earlier in this report (section 3.4), until gas markets are mature, “negotiated access” should not be interpreted in a “*laissez-faire*” sense that would necessarily involve a process of inquiring and awaiting responses concerning the availability, terms and cost of firm capacity or “on-demand” interruptible service. The *laissez-faire* interpretation would risk discrimination against third parties, if affiliates can use the transmission system on short notice *without* having to bargain for the particular terms of service. Moreover, the delays involved in bargaining can prevent short-term transactions that are essential to market development. Negotiations also open the door to the abuse of commercially sensitive information by TOs, who in the process acquire information about the locations of their competitors’ customers. Finally, bargaining in immature markets will result in higher transmission prices for those third parties that have weaker leverage with TOs. This violates the principles of discrimination and cost-reflective rates, which imply that the same prices should apply to all customers who impose the same costs on the system.

Until markets are mature, we conclude that the principles of the Directive will require TOs in negotiated access regimes to publish sufficient information on the terms, availability and price of services so that third parties can arrange access in a matter of hours, not days or weeks. It would not be acceptable to have TOs publish commercial conditions that represented merely an opening negotiating position, which third parties would have to reduce by arguing, bargaining and making counteroffers. In addition, Member States may wish to allow the TO the right to negotiate additional, customer-specific services. However, such a right must be surrounded by rigorous safeguards to prevent abuse:

- the conditions described above regarding the availability of standard, non-negotiated services still apply;
- the terms and conditions of any customer-specific services agreed in negotiations are published;

- the regulator or dispute-settlement authority actively scrutinises such arrangements for signs of discrimination, and is empowered to impose effective sanctions if necessary.

The principles of the Directive and EU competition law also have implications for the pricing of the standard services offered under negotiated access. The need for prompt service by third parties and the requirements for cost-reflectivity together imply that published prices cannot represent the optimistic hopes of the TO, but must already be designed to recover no more than the underlying costs of the service. As we describe in a separate section below, one logical implication is that even in negotiated access regimes, published prices can be no higher than would be justified by a transparent tariff model that measures and allocates the capital costs and operating costs of the system to all services.

Negotiations in Mature Markets

After markets are mature, the dangers implicit in customer-specific negotiations of prices and services will recede. By the time that a market matures, the transmission operator(s) will have, for several years, provided non-discriminatory access in the form of basic services at reasonable prices. By then the basic services must have proven sufficiently comprehensive and attractive to facilitate “repackaging” in competition with a TO’s more customised offerings. The continued availability of basic services and the potential for their repackaging will protect customers from the dangers of negotiations.

A specific example of a customised service illustrates the potential benefits offered by negotiations in a mature market. For example, a particular customer may be able to tolerate interruptions for up to three consecutive days a year. This flexibility may allow the pipeline to increase utilisation and make more firm capacity available to others. The pipeline and the customer might therefore negotiate a discount relative to the price of firm service in exchange for a contract specifying up to three consecutive days of interruption per year. Varying degrees of “firm service” such as this make economic sense and are available in developed gas markets.

If the market is mature, then the customer in this example will have the alternative of simply replicating a “three-day interruptible firm service” without negotiating directly with the TO. The customer would first purchase firm service and then sell three consecutive days of its entitlement to third parties on the secondary market. The mature market will have sufficient liquidity and diversity of players that the customer in this example will not have significant difficulty identifying potential customers on the secondary market or engaging in transactions. If these conditions hold, then the alternative of negotiating with the pipeline will present an opportunity rather than a threat of abuse or discrimination.

We conclude that in a mature “negotiated access” regime it may be efficient for pipelines to publicise a basic menu of services such as firm and interruptible services, while allowing market participants to negotiate for some supplemental services that are customised to diverse customer needs. In such cases, the dichotomy that may arise between “basic” services and the “negotiated” services has important implications for

pricing. Although the Directive requires the publication (in the case of negotiated access) of the “main commercial conditions for the use of the system” (Article 15), we do not interpret this provision as requiring specific pricing rules to be specified in advance for every service that might conceivably be provided. Rather, its principles can be implemented by adopting an appropriate tariff regime for the *basic* services, and then permitting considerable flexibility in the pricing for *negotiated* services.

Conclusions and Recommendations

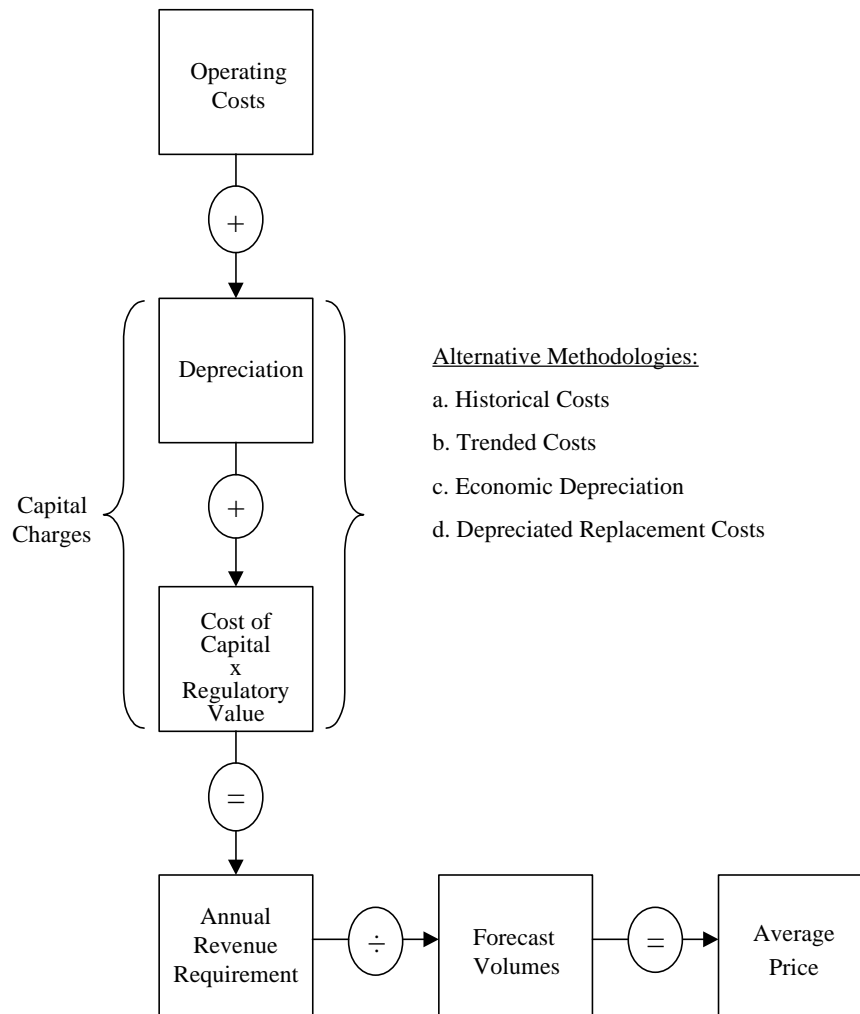
1. In recently liberalised markets, the existence of “negotiated access” should not be interpreted in a *laissez-faire* sense that would necessarily entail a process of inquiring, waiting for responses and bargaining to derive final terms for service.
2. TOs in “negotiated access” regimes should develop standardised terms of basic services that can allow their purchase by third parties in a matter of hours, rather than days or weeks.
3. In addition to the basic services, Member States may wish to allow TOs the right to negotiate non-standard access terms with individual customers on a case-by-case basis. However, until a market is mature, the negotiation of customised services should be accompanied by rigorous safeguards. The basic, non-negotiated services should still be available; the terms and conditions of any customer-specific services agreed in negotiations should be published; and the regulator or dispute-settlement authority should actively scrutinise such arrangements for signs of discrimination, and be empowered to impose effective sanctions if necessary.
4. The published prices for the basic services cannot represent an initial bargaining position by the TO, and should be no higher than justified by a transparent tariff model that measures and allocates the operating and capital costs of the system to all services.
5. These safeguards can be relaxed only when the market is judged to be mature. The market’s maturity should be measured by the ability of customers to derive their own customised services by engaging in secondary market transactions rather than negotiating directly with the pipeline.

5. Pricing of Services

5.1. Tariff Regime and Total Revenues

For pipeline companies that possess market power, charges should be designed to recover no more than reasonable operating costs, taxes, and capital charges that provide a competitive return on investment. Capital charges include both an allowance for depreciation and the cost of capital applied to the depreciated investment value. Regulators in Member States and in other countries have set pipeline prices on this basis. In Figure 2, below, we provide a schematic of the fundamental structure of a tariff model:

Figure 2: Basic Elements of a Tariff Model



The Directive leaves considerable discretion to Member States, but a key regulatory principle is common to the various methodologies employed internationally: *over time an efficient pipeline should not anticipate earning more than a competitive return on*

investment.²² Only the exploitation of market power can be anticipated to confer a higher return systematically. Monopoly profits are inconsistent with the Directive's concerns with efficiency, competition and the potential abuse of dominant positions. Article 22 establishes a concern with preventing the abuse of dominant positions. Excessive pricing facilitates discrimination by the incumbent in favour of related undertakings, in contravention of Articles 7 and 10.

Monopoly pricing is also an infringement of EU competition law, namely Article 82 EC. Whilst there is no recent case law in this respect for the gas sector, the general prohibition of excessive pricing by dominant companies is well established case law, as can be seen from the following quotation of the ECJ judgement in case 27/76, *United Brands*:²³

248: The imposition by an undertaking in a dominant position directly or indirectly of *unfair purchase or selling prices* is an abuse [...] under Article 86 (today 82) of the Treaty (emphasis added).

249: It is advisable therefore to ascertain whether the dominant undertaking has made use of the opportunities arising out of its dominant position in such a way as to reap trading benefits which it would not have reaped if there had been normal and sufficiently effective competition.

To prevent the abuse of market power, any proposed rate-making methodology must be designed to satisfy the “net present value” or “NPV test” for specific assets over time. That is, *the present value of capital charges associated with the construction or purchase of an asset should not exceed the present value of the associated capital outlays*. Capital charges that are consistent with the “NPV test” allow the pipeline owner to expect a “fair” return on investment, *i.e.*, the same expected return as would apply in a competitive market from investments of equivalent risk.

The “NPV test” can be considered as a way of comparing the price charged for the pipeline's services with their economic value, where the latter is defined as the expected cost of provision including a competitive return on investment. In this respect, reference is made to the judgement of the ECJ in case 26/75, *General Motors Continental*:²⁴

It is not disputed that in the five cases to which the Commission refers [...] the applicant imposed a charge *excessive in relation to the economic value of the service provided*. (emphasis added)

Although this report focuses on the “NPV test”, we should point out that EU competition law provides an alternative method to establish excessive pricing, that may also be applicable to natural gas transportation services. This is a comparison of the price

²² The term “competitive return” is here understood to mean the return that could be expected by investing in alternative assets with a similar risk profile. It is typically estimated using standard financial economic tools such as the Capital Asset Pricing Model.

²³ ECR 1978, p. 207, paras. 248 and 249.

²⁴ ECR 1975, p. 1367, para. 16.

with prices charged for identical services in other Member States. In this respect, reference can be made to the judgement of the ECJ in case 110/88, *Lucazeau v. SACEM*.²⁵

When an undertaking holding a dominant position imposes scales of fees for its services which are appreciably higher than those charged in other Member States and where a comparison of the fee levels has been made on a consistent basis, that difference must be regarded as indicative of an abuse of a dominant position. In such a case it is for the undertaking in question to justify the difference by reference to objective dissimilarities between the situation in the Member State concerned and the situation prevailing in all the other Member States.

However, such price comparisons are inherently difficult because of the difficulty of establishing parity of services, and accounting for relevant differences in underlying costs. These problems are compounded for pipelines and related assets by the difficulty of accounting for differences in asset valuation techniques and rate-making methodologies across different systems. Claims by incumbents that their rates are justified on the basis of comparison with other systems should therefore be examined with great rigour. Only the “NPV test” can be considered to provide definitive proof that pricing is not excessive.

Finally, we note explicitly that the so-called “market value principle” whereby gas is priced at the highest level that does not induce the customer to switch fuels is an example of monopoly pricing. In a competitive market, competition forces prices to reflect costs (including a competitive return on investment). In contrast, natural gas prices under the market value principle are independent of costs, and determined only by the price of alternative fuels. The same comment applies equally to the pricing of transportation, storage and other services.

Alternative Rate-making Methodologies

*The “NPV test” can be satisfied by regulation based on such different methodologies as “historical costs”, “trended costs”, “economic depreciation”, and “depreciated replacement costs”. In methodological terms, the key requirement for ensuring that any set of “regulatory accounts” satisfies the “NPV test” is that any increase in the value of an asset over time must be applied as an offset to the depreciation allowance in determining capital charges.*²⁶

Appendix 6 describes in some detail the various methodologies listed above. Of these approaches, *we recommend the use of “economic depreciation”*. Economic depreciation has several advantages:

²⁵ ECR 1989, p. 2521, para. 25.

²⁶ This has the implication that if a pipeline is fully depreciated over time, then the tariffs charged after that point should do no more than recover operating costs. In practice, new investment generally increases the asset base value as fast as it depreciates, and such situations typically do not arise.

- If the methodology is designed to track inflation in pipeline construction costs over time, then it has the merit of producing charges that should not vary significantly between old and new pipelines.
- It can be designed to produce stable charges even as throughput changes over time. For example, if low volume is anticipated in the first few years of a pipeline's life, then the economic depreciation method can be designed to ensure that those volumes do not pay higher prices. Rather, the methodology can ensure that charges per unit volume remain steady in inflation-adjusted terms over time, by postponing a portion of capital recovery until higher volumes materialise. Prices in competitive markets behave similarly.²⁷

Valuation of Pipeline Investment

Application of the different methodologies described above and in Appendix 6 requires assignment of an “initial regulatory value” to the assets in question. In practice, the valuation of existing investment can be extremely contentious. Although “historical acquisition cost” should be identical to “replacement cost” on the day that an asset is constructed, the two valuation techniques can be expected to diverge significantly after an asset is placed in service. The choice of valuation technique therefore has serious implications for the present value that alternative TOs can expect to recover on existing investment.

Valuation principles differ for TOs that have been recently privatised and those that have not. For privatised pipelines, the price paid to the government for the assets represents a natural reference point for valuation. If the purchase price of the assets is used in a tariff model that meets the NPV test, then the present value of capital charges over time can be expected to match the price that the government received for the assets. This offers a natural balance between the interests of consumers and shareholders: consumers pay in the aggregate a present value equal to the proceeds that the government received for the assets. At the same time, shareholders receive a competitive rate of return on the amount that they paid to the government. This is the system that has been used by the British government to value the privatised assets of the British Gas pipeline system.

Greater discretion should be allowed in determining the initial asset base for pipelines that continue to be owned by the government, as the choice presents several trade-offs for government policy and the typical concerns of monopolistic abuse do not apply. A high asset base allocates the costs of assets directly to end-users, while a low asset base implies that full capital recovery will rely to some extent on the general tax revenue. However the principles of the Directive imply two constraints to the selection of an initial asset base.

²⁷ We note that other techniques, such as a five-year “RPI-X” system applied to a depreciated purchase price, can also contribute to steady prices over time. The regulatory formula adopted in the most recent British Gas price control provides an example.

First, an excessive rate base can impede economic cross-border flows and reduce opportunities for third parties to compete effectively. This suggests that the initial rate base should not normally exceed the depreciated replacement cost of an optimised system.

Second, the government must ensure that too low an asset base will not prevent the efficient construction of new pipelines by private parties. For example, imagine that a particular pipeline has been subsidised heavily prior to the liberalisation of natural gas markets, while another competing pipeline has not. The government believes that the tariff model for the subsidised pipeline should employ a discounted asset value so that consumers pay low pipeline prices reflecting the subsidies they have already “paid” through taxes. This approach could distort competition with the competing, unsubsidised pipeline, and in particular could lead to inefficient capacity expansion decisions. One solution to this problem may be to redistribute the subsidies in a competitively neutral manner. For example, the previously subsidised pipeline may be allowed to make higher charges, but the “excess” part of its revenues could be distributed evenly among consumers of both pipelines, including consumers of new capacity on either.

For companies that have always been privately held, we recommend that the initial asset base in the tariff model be based on the depreciated book value of the underlying assets. Experience in other markets suggests that, on the eve of liberalisation, TOs have an incentive to revalue their assets upward and use the higher figures for the initial asset base of the tariff model. Such revaluations should not be permitted. If the TO seeks to use a higher figure than the depreciated book value of system assets, it should have the burden of demonstrating that to date it has recovered less of its capital than implied by the total cumulative depreciation in its accounts. Such a demonstration would involve a comparison of historical cash flows to the cost of capital and to the accounting depreciation figures since the relevant assets were placed in service. If transportation pricing and expenses were not historically separated from other activities, then a reasonable compromise would be to conduct the exercise for the TO in the aggregate, but to apply the aggregate *percentage* capital recovery specifically to the transmission system assets.

As the example given above (the competing subsidised and non-subsidised pipelines) suggests, problems can arise whenever competing pipelines are valued according to different methodologies. Similar problems arise when different pipelines’ capital charges are determined according to different methodologies, as discussed in Appendix 6. Although the use of economic depreciation minimises such distortions, they may still require further regulatory intervention.²⁸

²⁸ In contrast to economic depreciation, other methodologies can lead to tariffs that fall over the lifetime of the pipeline. A new pipeline competing with an old one is therefore disadvantaged because its rates are at their historic high while its competitor’s are at their historic low.

Cost of Capital

The cost of capital used to derive tariffs should itself be derived from one of the several widely-used financial methodologies. The analysis should be in a transparent form, open to assessment by third parties.

Tariffs in Negotiated Access Regimes

The principles of pipeline charging do not differ in countries that rely on negotiated access rather than regulated access. Tariffs that do not satisfy the NPV test contain elements of monopoly profit, and are therefore incompatible with competition law and the Directive. It is therefore essential that under negotiated access incumbents adopt transparent tariff models that satisfy the “NPV test”. Not only do such models prevent the incumbent from earning excessive profits over time, they help prevent discrimination by vertically integrated incumbents. An incumbent should be in a position to justify pipeline charges to its affiliates and third parties by reference to such a model.

The use of a tariff model that satisfies the “NPV test” does not undermine the flexibility that some may desire from the negotiated access system. As we have explained above, flexibility can be preserved by the idea of a “basic service” and a “negotiated service”. The key is to offer a basic service that is sufficiently comprehensive and attractive to enable effective competition by market participants. In such cases the incumbent’s charges can be defended as reasonable if, in the absence of negotiated services, the resulting basic service revenues would meet the NPV test of a transparent tariff model.

Incumbents who are allowed discretion over the pricing of negotiated services may be able to earn more than a competitive return of investment from the attractiveness of negotiated services tailored to unique customer needs. However, the prospect of some profit from creative solutions would seem critical to motivate their provision. If the basic service is truly attractive, then negotiated services should arise only on rare occasions when customers face unique circumstances. In a mature market, the profits arising from such creative solutions do not arise from abuse of monopoly power. Rather, potential market power over the provision of negotiated services is constrained both by the alternative of a cost-reflective basic service and by the potential for third parties to provide competing solutions through “repackaging”.

In negotiated access regimes, objectivity and transparency are special considerations in deciding whether a tariff methodology complies with the principles of the Directive. The principle of non-discrimination is most easily satisfied if the tariff methodology cannot be manipulated in favour of affiliated undertakings. This counsels against the use of the “depreciated replacement cost” methodology, in which pipeline owners retain considerable discretion over both the timing and potential outcome of studies to revalue their assets. Although the requirement to meet the “NPV test” means that a pipeline cannot influence the net present value of charges by revaluing its assets in any particular

manner, discretion over pipeline valuation still implies discretion over the time profile of charges. In particular, revaluation of the asset's replacement cost in a given year can produce a "spike" in total charges.²⁹ The incumbent may have discretion to pick the year with the price spike simply by manipulating the timing of a replacement cost study, or by influencing the study's outcome. Such discretion can be used to the advantage of affiliates, by targeting price spikes in periods where potential competition by third parties is of greatest concern. *Because the potential abuse of the "depreciated replacement cost" methodology is difficult to monitor, the principles of the Directive are best satisfied if pipelines in negotiated access regimes use other methodologies.* Similar factors have motivated regulators in different contexts to shift from "depreciated replacement costs" to "trended cost" systems that rely on objective inflation indices.

Conclusions and Recommendations

1. Pipeline transportation charges in both regulated and negotiated access regimes should derive from transparent tariff models. Charges should satisfy the "NPV test", which is a standard part of regulatory accounting methodology. It requires that pipeline charges recover on expectation no more than operating costs, taxes, depreciation and the cost of capital on existing investment.
2. Charges in excess of those given by the NPV test contain an element of monopoly profit and are therefore inconsistent with the Directive and with EU competition law.
3. We recommend the use of the rate-making methodology known as "economic depreciation", which produces steady real charges over time.
4. The initial valuation of the pipeline system for a privatised TO should be derived by reference to the purchase price.
5. For assets still owned by the government, the initial valuation of pipeline assets should not exceed depreciated replacement costs unless an affirmative demonstration can be made that the resulting charges would not affect competition adversely. Care should also be taken to ensure that asset values that reflect prior government subsidies do not impede the construction of new pipes. This may require compensation between pipelines for the effects of prior subsidisation.
6. For TOs that have always been private, the following rules should apply to the initial asset value:
 - a) the assets should be valued at their depreciated book value, unless the TO can demonstrate that capital recovery to date has been less than indicated by the cumulative depreciation figure;

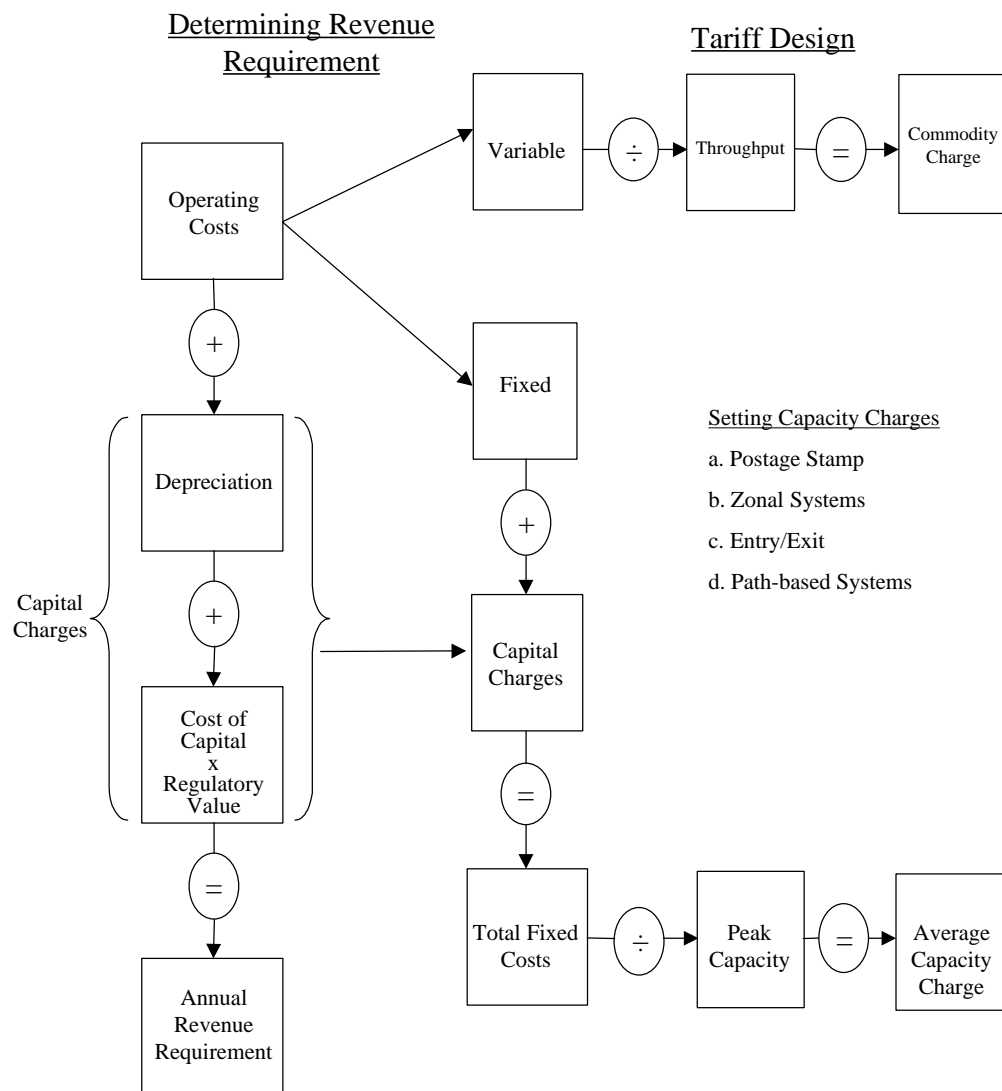
²⁹ Table A6 in Appendix 6 provides an example of such a spike.

- b) upward revaluations of pipeline assets on the eve of liberalisation should not be allowed; and,
 - c) total valuation should not exceed the depreciated optimised replacement cost of a new pipeline.
- 7. The cost of capital used to derive tariffs should itself be derived from one of the several widely-used financial methodologies. The analysis should be in a transparent form, open to assessment by third parties.
- 8. Replacement cost valuation techniques should not be used in negotiated access regimes.
- 9. Changes in the rate-making or asset valuation methodologies of a tariff model should not be allowed to generate windfall gains or losses.

5.2. Design of Charges for Individual Services

The proper level of total revenues follows from the “NPV test” requirement discussed above. However, the detailed structure of pipeline usage charges is a separate issue. In Figure 2 we provided a schematic for a basic tariff model, which determined the annual revenue requirement for a system. We reproduce the schematic below in Figure 3, elaborated to show the issues of cost allocation that arise when developing particular tariffs. By tariff design, we refer to the allocation of different elements of the revenue requirement, which were discussed above, to different tariff components (*e.g.*, fixed and variable charges).

Figure 3: Designing Tariffs



In accordance with the underlying principles of the Directive, *charges should ensure efficient utilisation of the system*, subject to the conditions of zero NPV and non-discrimination between customers. Economic theory suggests that efficient utilisation is best achieved through short-run marginal cost pricing, which will ensure that transmission services are employed whenever the value they contribute exceeds the marginal cost of using them. However, marginal cost pricing is not in general feasible, because it typically is insufficient to recover the full fixed costs of the pipeline, particularly those with spare capacity. Charging only marginal costs would provide no contribution to the recovery of fixed costs, which typically constitute over 90% of total costs.

These circumstances imply the need for a two-part tariff, consisting of an annual capacity charge based on peak usage plus a commodity charge based on actual gas flows. Economic theory suggests that *the commodity charge should be set close to variable cost, and the capacity charge established at a level sufficient to recover the pipeline's fixed costs*.³⁰ In practice, this typically involves a split that recovers approximately 90% of costs through the fixed charge, and 10% through the variable charge (a “90/10 split”).³¹ Fixed costs should typically *not be allocated to transactions such as swaps that may alleviate congestion*.

If capacity is scarce at peak periods, then the principle of marginal cost pricing requires that congestion costs be reflected. These costs are given by the competitive market demand for capacity. When capacity is scarce, efficiency therefore requires that users pay competitive market prices. As discussed above, this is best achieved through an *active secondary market in firm capacity rights*, together with mechanisms to prevent market dominance. Indeed, efficient secondary markets prevent the charges for primary firm capacity allocations from affecting efficiency, at least in the short run.³²

Prior to the emergence of a competitive secondary market, efficiency requires that a pipeline charge competitive prices for peak capacity. However, the problem of excess cost recovery must also be avoided. A potential corrective mechanism might be a dedicated fund to collect the excess profits. Such a fund could be used to defray the costs of future capacity expansions and/or public service obligations. In the former case, the rate base would be suitably adjusted to prevent the pipeline owner from then recovering the excess profits via revenues from the expanded capacity. In our discussion of tariff

³⁰ See for example Armstrong, Cowan and Vickers, “Regulatory Reform: Economic Analysis and British Experience”, MIT Press: London, 1995, pp. 53-54.

³¹ The 90/10 split is typical in North America and Australia. In the United Kingdom, Transco charges are currently at a 65/35 split (Transco, *Transportation Ten Year Statement 1998*, p. 140), up from a 50/50 split prior to 1997 (*British Gas plc – Volume II of reports under the Gas Act 1986 on the conveyance and storage of gas and the fixing of tariffs for the supply of gas by British Gas plc*. MMC August 1993, Appendices 6.6, 6.7, pp. 399-400).

³² As discussed above, the pricing of primary capacity has long-term efficiency implications through the incentives it creates for pipeline expansion. See “Pipeline Pricing to Encourage Efficient Capacity Additions”, Brattle Group Working Paper, prepared for Columbia Gas Transmission Corporation, February 1998, (available on request from the authors).

design below, however, we focus on standard methods for recovering fixed costs rather than the use of market-based congestion pricing by the TO. The standard methods include a “postage stamp” capacity charge, “zonal” systems, “entry/exit” systems, and “path-based” systems.

Conclusions and Recommendations

1. The fixed costs of the transportation system should be allocated to capacity charges for firm capacity.
2. “Commodity” or “usage” charges should be designed to recover no more than the variable costs of transportation.
3. Fixed costs should typically not be allocated to transactions such as swaps that tend to alleviate congestion.

5.3. Pricing Methodology and Cross-Border Transactions

We now consider the various pricing methodologies for fixed cost recovery from the perspective of ensuring the promotion of efficient cross-border transactions. The Directive's goal of fostering a competitive internal market, and the principle of non-discrimination, imply that no pricing methodology should be used that discriminates against cross-border transactions. This requirement applies equally to transactions crossing national borders and to those which cross the borders of different transmission and/or distribution systems within a single Member State.

In this section we analyse the principal natural gas charging methodologies, and make recommendations for the *harmonisation of pricing methodology around a principle of "broad cost-reflectivity"*. Implementation of this principle need not involve a harmonised choice of specific methodology, such as "postage stamp" or "entry/exit". However, if different specific methodologies are adopted then market participants including incumbents, third parties and regulatory authorities should agree further harmonisation measures at a more detailed level.

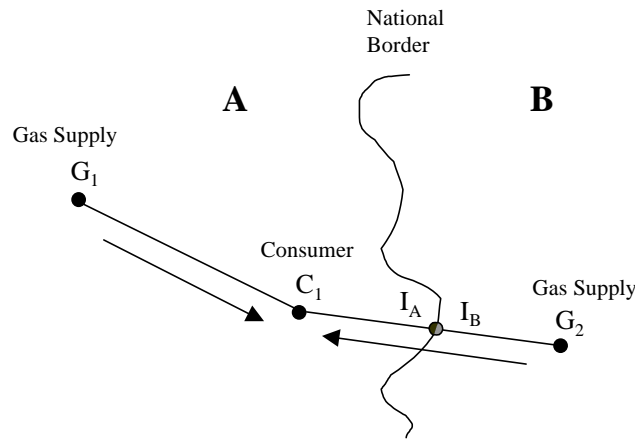
We note that the methodologies analysed can all in principle be applied whether capacity rights are sold at a fixed price or in auctions: for example, in the United Kingdom Transco uses an entry/exit charging methodology, with entry rights sold by auction.

Potential for Discrimination

Discrimination against cross-border flows can arise under each of the principal natural gas transmission charging methodologies used in different countries, and depends on the details of implementation. Below we illustrate the potential for discrimination against cross-border flows under postage stamp, zonal, entry/exit, and path-dependent charging methodologies. We also identify possible solutions to such problems.

Figure 4 illustrates an example of two neighbouring countries, "A" and "B", where a consumer in country "A" has the option of a domestic or cross-border transaction. The consumer is identified as point " C_1 ", the domestic supply source is " G_1 " and the foreign source is " G_2 ". In this example we assume that the true economic costs of transporting gas to the consumer from either gas source are equal. Any regime under which the total costs imposed on the cross-border transaction differ significantly from those of the domestic transaction is therefore discriminatory. Even if the economic costs of transportation from the two sources are not exactly equal, the regime will be discriminatory if the difference in charges is significantly greater than the difference in economic costs.

Figure 4: Cross Border Gas Supply



Postage Stamp

We first consider a “postage-stamp system” (in a situation where there is one TO “per country”). Under a pure postage-stamp system all transactions in country A pay the same transportation charge, regardless of their origin or destination. The same system applies in country B. The postage stamp charge in each country is designed to recover the average costs of using the country’s transmission network. For natural gas transmission, a natural variant on the “pure” postage-stamp system would involve a fixed charge that is independent of origin or destination, plus a commodity charge that covers the variable costs of transmission and is therefore not independent of origin or destination.

Discrimination arises if the cross-border transaction incurs the postage-stamp charges of both countries, while the comparable domestic transaction incurs only country A’s charge. This phenomenon is known as “pancaking” (because the accumulation of charges is analogous to the way that Americans pile pancakes in a stack on the plate).

The economic impact of any discrimination depends on the breakdown of charges into fixed (“capacity”) and variable (“commodity”) components. For example, the postage-stamp charges may involve a fixed annual payment for capacity, supplemented by a minor commodity charge per unit output designed to recover variable costs. In this case, there may be effective discrimination against cross-border transactions. However, imagine that under this system transactions of less than one year that do not require incremental capacity incur only the commodity charge. Then the system provides no significant impediment to the development of off-peak, short-term transactions.

If, by contrast, the postage-stamp methodology relies entirely on a “commodity” charge per unit throughput to recover all network costs, then the discrimination against cross-border trades may also impede the development of any short-term market. We identified above several advantages to recovering the fixed costs of the network through fixed capacity charges, and recovering only the variable costs of the system through a

“commodity” charge per unit throughput. An additional merit to this proposal is to minimise any potential discrimination against short-term, off-peak cross-border trading. It does not, however, resolve the problem of discrimination against long-term cross-border transactions.

In the example above, the pancaking can be avoided by waiving the transmission fee of either country “A” or “B”. However, this solution may prompt a need for compensation arrangements between interconnected pipeline networks. An analogy can be found in the interconnection arrangements of independent telephone networks. Customers typically pay the same for a telephone call even if it originates in one network and terminates on another: there is no pancaking of charges. In some situations the independent networks perceive no need for formal compensation arrangements among themselves. They are said to adopt a “bill and keep” policy, as each network simply bills the customer who originates the call, and keeps the associated revenue. The service of terminating the call on another network is effectively provided free of charge. However, a bill and keep policy is only stable where a similar number of inter-network calls are anticipated to terminate on each of the networks involved. Anticipated imbalances in inter-network traffic often prompt formal compensation policies in interconnection agreements. The arrangements allow each network to avoid pancaking while compensating the interconnected network for the service of terminating calls.

If interconnected pipelines adopt a compensation agreement with charges analogous to the interconnection fees of the telecommunications industry, the resulting charges must be cost-reflective. Interconnection fees that are not cost-reflective do not satisfy the requirements of the Directive, because they enable a vertically-integrated incumbent to discriminate against cross-border trades. For example, imagine that the incumbent in country “A” controls the pipeline network in its country as well as the gas supply source. To comply with the Directive, the incumbent waives its postage-stamp fee for all transactions that originate in country “B” and that cross the border for delivery to consumer “C₁”. However, cross-border competition can be thwarted if the incumbent in country A imposes an inappropriate interconnection fee on country B. For example, the interconnection fee may be designed to indemnify the incumbent from competition—the fee could be set equal to the incumbent’s profit derived from supplying C₁ domestically. This profit may significantly exceed the direct costs of delivering gas from the border to C₁.

Such an interconnection fee becomes a direct cost of supply to the supplier in country B, if that supplier is vertically integrated with the network. In this case, the interconnection fee discriminates against cross-border trades, regardless of the tariff regime. If the same supplier were located inside country A then it would be unaffected by the fee.

If the supply source G₂ is not related to the pipeline network in country B, then the high interconnection fee may not affect its behaviour. The interconnection fee is paid by the network owner in B, and allocated across all transactions by the postage stamp system in that country. However, cost-reflectivity would still be a concern. The network owner in B has an incentive to discourage cross-border trades, because of the high

interconnect fees they impose on the network, and in practice it can always use non-price mechanisms to hinder such transactions. Alternatively, the network owner in B may be forced to raise the postage-stamp rate, or to depart from postage-stamp rates to a charging system that allocates the interconnection fee more directly to cross-border flows. In either case, cross-border trade is threatened.

The principles applicable to interconnection fees that avoid “pancaking” are identical to those covered in our discussion above of cost recovery and tariff design. Any interconnection fees should be designed to recover no more than the underlying costs of providing the service on a present value basis. The fees should allocate fixed costs to uses that involve firm capacity, while off-peak transactions should generally be associated with fees that recover variable costs only.

Zonal Pricing

Discrimination against cross-border trades can also arise under a system of zonal pricing. We use the term “zonal pricing” to describe a system where prices differ for transactions that cross specific geographic zones, but are uniform to all transactions within a zone. The same principles that we have discussed with respect to pancaking under a postage-stamp system apply to zonal systems. Indeed, the postage stamp system can be viewed as a variant of a zonal system, where the zone borders happen to coincide with those of the independent, interconnected networks. To express the problem of pancaking more generally in terms of a zonal system, it arises when the cumulative charges for a cross-border transaction exceed those applicable to a comparable domestic transaction for reasons that cannot be attributed to underlying costs.

Entry/Exit Pricing

An “entry/exit” charging system imposes discrete charges for the use of each location where gas can be injected or withdrawn from the network.³³ Discrimination against cross-border trades can also arise under such a system. Table 3 illustrates a case of apparent pancaking, built upon the example in Figure 4. The domestic transaction in country “A” would incur an entry charge at point G_1 and an exit charge at point C_1 . The comparable cross-border transaction, however, is assumed to incur both an entry and an exit charge in each country. The entry charge in country A would apply at the interconnection point I_A , while the same point would attract an “exit charge” from country B shown as I_B .

³³ For a given entry point, the entry charge is a single number that is independent of the intended or actual destination of the gas being injected. However, each entry point can have a different entry charge. The same comments apply to exit charges.

Table 3: Apparent Pancaking under Entry/Exit Pricing

	Country B	Country A	Total
Domestic Flow		Entry G_1 + Exit C_1	$G_1 + C_1$
Cross Border Flow	Entry G_2 + Exit I_B	Entry I_A + Exit C_1	$G_2 + I_B + I_A + C_1$

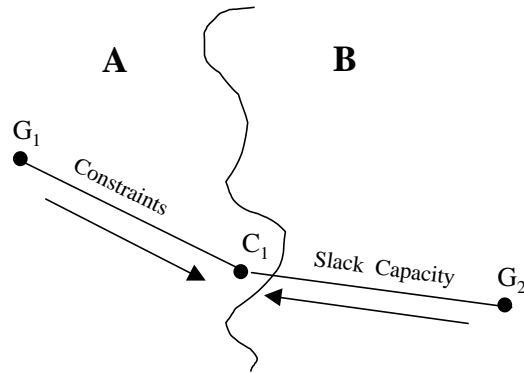
Avoiding “pancaking” in the above example of an entry/exit system would appear to require the removal of any entry or exit charges associated with the point of interconnection. This solution is illustrated in Table 4. If the entry and exit fees are properly cost-reflective then this solution does not require an interconnection fee between countries A and B. The relevant entry and exit fees should already reflect transmission costs, including those arising from cross-border transactions. For example, imagine that G_2 and C_1 serve each other exclusively: all gas supplies from G_2 are contracted to C_1 , which does not purchase gas from any other sources. If countries A and B consider these contracts in designing cost-reflective entry and exit charges, the natural result will not require any explicit interconnection fee. Country A’s exit charge can be expected to recover the costs of its network from point I_A to point C_1 , while Country B’s entry charge can be expected to recover the costs of its network from G_2 to I_B .

Table 4: No Apparent Pancaking

	Country B	Country A	Total
Domestic Flow		Exit G_1 + Entry C_1	$G_1 + C_1$
Cross Border Flow	Exit G_2	Entry C_1	$G_2 + C_1$

Matters become more complicated in this example if the points G_2 and C_1 do not serve each other exclusively. For example, assume that C_1 also takes gas from G_1 , and that peak flows from G_1 to consumption point C_1 confront system capacity constraints, but simultaneous flows from G_2 do not. The situation is illustrated in Figure 5. In this case, *the simple omission of the interconnector itself as an entry or exit point does not prevent discrimination against cross-border trades*. Our reference to the lack of any “apparent” pancaking in Table 4 was premised on comparable costs between the domestic and cross-border path, which no longer holds in Figure 5. Arguably, incremental flows from G_2 to C_1 could actually *reduce* the costs of the network in country A by avoiding the need to construct reinforcements between G_1 and C_1 . If incremental flows from G_2 actually reduce the costs of the network in country A, then the use of a common “exit” price at C_1 regardless of the origin of the gas must be questioned. To avoid discrimination against cross-border flows, country A would have to refine its charging system to introduce appropriate discounts if consumers at C_1 imported gas supplies from country B at peak periods.

Figure 5: With Constrained Pipelines

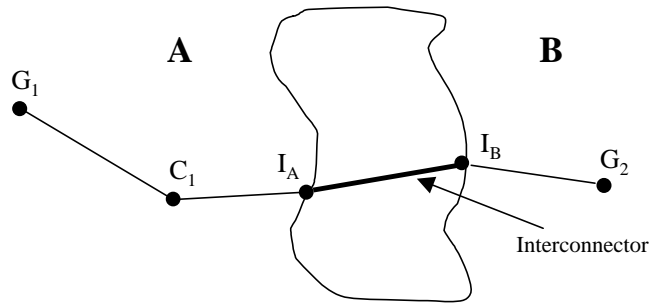


It can be argued that the “entry/exit” system of the British Gas pipeline system discriminates against deliveries through the Interconnector into Great Britain. Deliveries through the Interconnector can actually benefit the system by reducing the need to construct more reinforcements for gas flows from the North Sea to points in the south. Under the current system, southern consumers pay steep exit charges but there is no apparent procedure that would grant discounts if they could demonstrate that a portion of their peak flows came through the Interconnector. We recommend that Member States encourage industry participants to agree upon a pricing system that provides appropriate discounts in such circumstances. Where consensus is impossible, the regulator or dispute settlement authority should be empowered to demand appropriate revisions to the existing charges.

In “entry/exit” systems, appropriate treatment of cross-border transactions depends on whether the interconnection involves a significant amount of dedicated assets, such as an undersea pipeline.³⁴ Until now we have implicitly assumed that the interconnection itself does not entail additional costs. However, interconnectors such as those between England and Belgium or Scotland and Ireland represent significant investments. In that case, illustrated by Figure 6, an entry charge at I_A and an exit charge at I_B do not necessarily give rise to “pancaking”. If the total of I_A and I_B reflect the cost of capacity in the interconnector, then the entry/exit charging regimes may well be appropriate.

³⁴ The following remarks apply to a cross-border interconnection that involves an exceptional investment, such as an undersea interconnector. The presence of, for example, a compressor station would not qualify.

Figure 6: Countries Separated by Interconnectors



Path-Based Charging

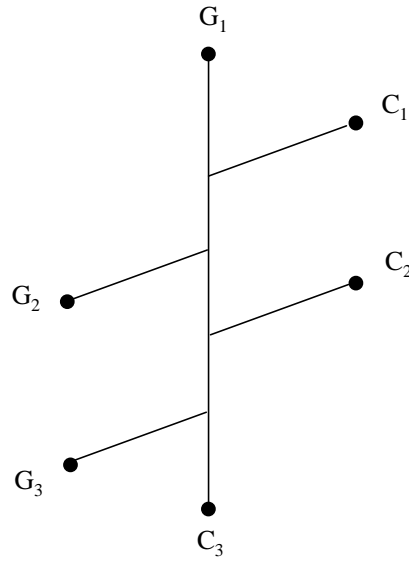
By “path-based” charging we refer to a system that involves different prices for different contract paths. Such charges would be reflected in a matrix of different prices depending on both the origin and destination of the gas, as shown in Table 5. One obvious example of path-based charging is the use of distance-based charges. However, distance-based charging is not in general cost-reflective. For example, it does not reflect the costs imposed by congestion.

Table 5: Path Dependent Charges

From	To			
	C_1	C_2	C_3	C_4
G_1				
G_2				
G_3				
G_4				

Although an “entry/exit” regime can also result in a matrix of unique charges for different contract paths, these paths have certain “dependencies” between them that would not in general arise under path-based charging. An example of such dependencies, and the potential problems that can arise is provided in Figure 7, which imagines three entry and three exit points.

Figure 7: Entry/Exit Points and Dependencies



In the configuration shown in Figure 7, gas can flow from any of the three entry points to any of the three exit points, giving a total of nine possible transit paths. However, under an entry/exit system all charges are derived from just six numbers, the entry/exit charges for the individual nodes of the system. Consequently, there must be dependencies between the charges for different transit paths. For example, the difference in charges for delivering at C_1 rather than C_3 is the same wherever the gas is sourced from. In particular, since the cost differential for sending gas to C_1 rather than to C_3 is the same whether gas comes G_1 or from G_3 , *there is no incentive in the prices to encourage an outcome whereby C_1 is served more by G_1 and C_3 more by G_3* . Given the relative locations of the nodes, however, having C_1 served more by G_1 and C_3 more by G_3 would probably be an efficient outcome. Certainly, the pipeline would be operated in this way. The example illustrates the potential for inefficiency under an entry/exit system.

If a path-based system identifies costs accurately, it will not discriminate against cross-border flows. Nor would it require any supplementary compensation mechanism between neighbouring countries (or TOs) using the same system. Furthermore, it has the advantage, which we discuss below, of automatically promoting efficient physical flows without the need for “swaps”.

Although a path-based system has desirable theoretical properties, it may not always be practical to implement. The fundamental trade-off between a path-based system and other types is one between theoretical economic efficiency and the demands of simplicity and flexibility.

- In some cases it is difficult or impossible to measure accurately the costs of different paths. This applies in particular to distribution systems, where we would not recommend the use of path-based charges.

- Path-based systems can reduce flexibility and increase uncertainty for consumers. For example, under a postage-stamp system the consumer pays the same price for gas deliveries regardless of its origin. This makes the transportation charges more predictable and facilitates comparison of gas prices between different supplies, as there are no differences in transportation costs for consumers to assess.
- A similar effect applies to suppliers. For example, under a postage-stamp system gas can be input into any point and delivered to any location without changing transportation costs. The system therefore eliminates the need to inform the system operator of pairings between particular system inputs and off-takes, which could prove cumbersome and limit flexibility.

Implementation of the Directive must recognise practicality, and the use of a postage stamp, zonal, entry/exit system or a hybrid can often be defended as economically reasonable, even if it does not capture every possible deviation in the costs of alternative paths. In particular, it is unlikely that a “pure” path-based system, where charges depend on the exact combination of entry and exit points, has any significant advantage over a zonal system with enough zones defined to capture the key cost determinants. Such a “pure” path-based system may lead to excessively complicated charges, and damage the liquidity of secondary markets in capacity.

It is possible to implement “hybrid” systems as well. For example, one country may employ a “postage stamp” tariff for domestic deliveries, but have different “path-based” charges for the service of transit through the country to another country. In such cases, the “path-based” charge could have the virtues of the methodology described above without the apparent defects. Transit flows may be sufficiently common and predictable that they represent little inconvenience or sacrifice of flexibility. Shippers can nominate the entry and exit point to the TO for each transaction and have unique prices for the few possible paths involved. However, when a TO wishes to implement a “hybrid” system, it should be required to prove rigorously that the differences involved in price and non-price terms respect the conditions of the Directive, *i.e.*, are cost-reflective and non-discriminatory. The existence of such differences should entail publication requirements and active scrutiny by the regulatory authorities.

Choice of methodology

We recommend that all Member States apply the following harmonised criteria to determine pricing methodology.

- To ensure the necessary degree of cost-reflectivity, it is necessary to assess the system configuration and likely prevailing flows for each interconnected system.
- Based on this assessment, significant cost differentials, such as the savings arising from likely backhaul transactions, should be identified.
- This exercise should be conducted both on a national level, and at a supra-national level or Community level.

- The particular pricing methodology chosen should provide as much simplicity and transparency as possible, while allowing for price differentials that reflect the cost differentials identified above.
- The implementation of these criteria represents a high level harmonisation of cross-border pricing. Market participants, including incumbents, third parties and regulatory authorities should agree further harmonisation measures at a more detailed level.

Implementation of This Recommendation

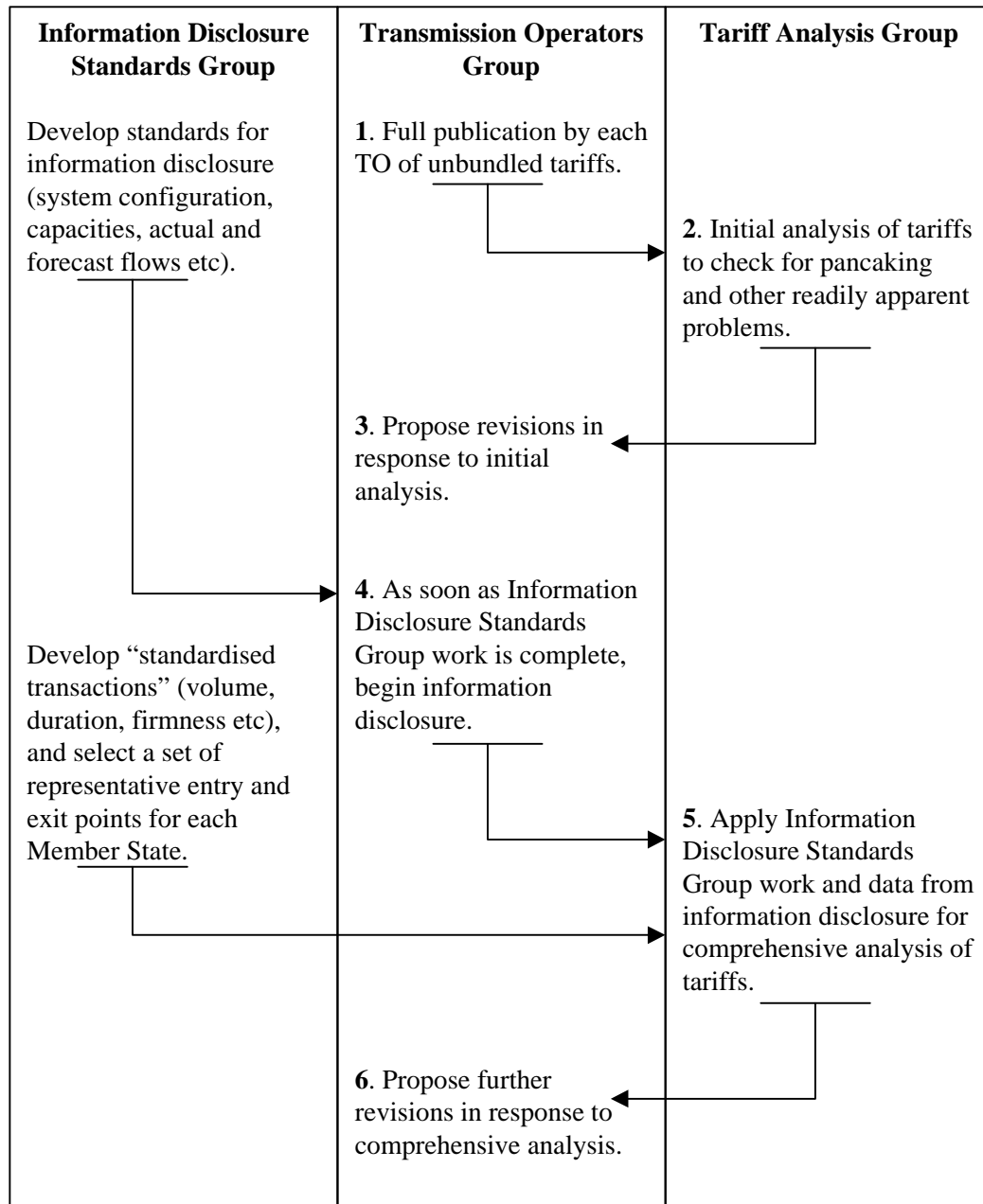
Because the proper treatment of cross-border flows depends on each TO's costs, flows, and pricing methodology, any solutions to the problem must rely on detailed analysis. However, we can recommend a process that Member States and market participants can follow to ensure that reasonable analyses and steps to redress problems are undertaken.

The process is illustrated in Figure 8 below. It involves three parallel sets of activity, carried out or co-ordinated by three different "working groups". The "Information Disclosure Standards Group", drawn from a wide range of system users, is charged with creating detailed standards for the publication of system-related information by TOs. Co-ordination in this area is essential as cross-border flows will necessarily pass through the pipes of several TOs, and a coherent understanding of underlying costs requires each TO involved to provide comparable information. Generally, the information provided should cover system configuration, actual and forecast flows, the capacity of different paths, existing or potential constraints on the system, representative reinforcement costs and the underlying tariff model. One example of good information disclosure in these respects is the "TRANSCOST" computer model that is produced by British Gas Transco and made available to market participants.

The Information Disclosure Standards Group should also agree on a few types of transactions that represent the way that they contemplate gas will be traded after market liberalisation. For example, a one-year trade, a monthly trade, a peak transaction, and an off-peak transaction of various sizes or load factors may provide a representative picture of future gas trading. The system users will agree that, to test the potential problems with the pricing of cross-border flows, only the standard transactions from this representative set will be used. Otherwise the types of complaints and analyses that could be performed on different tariff systems may get unwieldy. The choice of some specific unique type of transaction to lodge complaints about one TO, and the use of other quite different transactions to complain about another could open TOs to an infinite number of complaints.

Again, to make the analysis of cross-border flows reasonable, the system users should agree, through the Information Disclosure Standards Group, to "test" the tariff regimes of different TOs by focusing on only a subset of the receipt and delivery points on a system. System users will have an interest in ensuring that they choose the most important points for cross-border flows. Without this limitation of points, one could always come up with a complaint by "cherry-picking" among the dozens of potential paths involved.

Figure 8: Implementation of Tariff Methodology Recommendations



As indicated in Figure 8, two other working groups would be active in parallel with the activities of the Information Disclosure Standards Group, the “Transmission Operators Group” and the “Tariff Analysis Group”: the Transmission Operators Group would represent TOs, and where necessary co-ordinate their activities in the process. The Tariff Analysis Group would be drawn from as wide a range as possible of system users, TOs and other market participants. Their activities follow the sequence indicated:

1. First, all TOs would be required to publish actual or proposed unbundled transmission tariffs within a reasonable timeframe. This is critical because the

treatment of cross-border flows is not yet transparent in systems that have to date offered bundled services only. In some Member States, such as Belgium, unbundled tariffs are already published for transit flows but not for flows that terminate within the country. Potential discrimination against cross-border flows cannot be assessed until a full set of domestic and transit tariffs are published. Even for systems where domestic and transit tariffs are on offer, they do not yet involve the specific services recommended in this report: firm transportation and “on demand” interruptible service. Within the specified deadline, TOs should propose domestic and transit tariffs for both firm transportation and “on demand” interruptible service. TOs in negotiated access jurisdictions should not be exempt from this requirement. The Transmission Operators Group might usefully co-ordinate the publication, ensuring for example that all tariffs are published in a standard format to facilitate initial comparisons.

2. Once these tariffs are published, the Tariff Analysis Group should subject them to a preliminary analysis. Comprehensive analysis will require the completion of the work of the Information Standards Disclosure Group, and the subsequent publication of system information by TOs, which will undoubtedly take some time. However, some problems with the treatment of cross-border flows can be identified even without detailed knowledge of interconnected systems. For example, postage-stamp tariffs in neighbouring systems raise the possibility of pancaking that can be foreseen without detailed system information. We therefore recommend that the Tariff Analysis Group undertake a first round of analysis as soon as tariffs are published.
3. TOs would be required to respond to this initial analysis, and propose revisions where the analysis has identified problems with the initial tariff proposals.
4. As soon as the Information Disclosure Standards Group has produced standards for information disclosure, the TOs would begin the process of publication according to the disclosure standards promulgated (depending on relative speed, this could in principle precede step 3 above).
5. Once information disclosure was complete, and the Information Disclosure Standards Group had defined the standard transactions and selected representative entry and exit points, the Tariff Analysis Group would undertake a comprehensive analysis of tariffs, using the standard transactions and the selected entry and exit points to obtain a realistic picture of problems with the pricing of transportation for cross-border flows.

This process will inevitably involve a significant level of effort from all parties. However, we believe the rewards justify the level of investment: tariffs that respect the principles of non-discrimination and foster efficient cross-border trades, but avoid unnecessary complexity. While the *process* may entail some necessary degree of complexity, it should be conducted in a transparent manner, and its *results* should seek the maximum possible simplicity and transparency.

Conclusions and Recommendations

1. There is no single pricing methodology that guarantees appropriate treatment of cross-border flows. Member States should ensure that, whatever methodology is employed, cross-border pricing reflects the principle of “broad cost-reflectivity”. This entails:
 - Assessment of the system configuration and likely prevailing flows for each interconnected system.
 - Significant cost differentials, such as the savings arising from likely backhaul transactions, should be identified in this assessment.
 - This exercise should be conducted both on a national level, and at a supra-national or Community level, perhaps tied in to the Gas Regulatory Forum process.
 - The particular pricing methodology chosen should provide as much simplicity and transparency as possible, while allowing for price differentials that reflect the cost differentials identified above.
2. Postage stamp and zonal pricing systems may result in “pancaking” of charges for cross-border flows. Depending on the configuration of the pipeline system, the problem may be resolved by exempting the cross-border flow from the postage stamp or zonal rate in either the originating or terminating country. However, this solution may simultaneously create a need for supplementary payments between interconnected systems.
3. In “entry/exit” systems, appropriate treatment of cross-border transactions depends on whether the interconnection involves a significant amount of dedicated assets. If it does not, then there may be no need for a separate “entry” or “exit” charge for the point of interconnection. In cases like the Irish interconnector or the European interconnector, however, separate “entry and exit” charges at the interconnection point or a separate charge for use of the interconnection assets are appropriate.
4. A “path-based” charging system can avoid discrimination against cross-border flows, but may be excessively complex and offer insufficient flexibility in many systems. In general a zonal system with a sufficient number of zones to ensure that tariffs capture key determinants of cost is preferable to a “pure” path-based system where charges depend on the exact combination of entry and exit points. An alternative suggestion is to use separate “path-based” charges for transit through a country, while using another charging method for transactions that originate or terminate domestically. However, such a “hybrid” scheme should be rigorously scrutinised for potential discrimination.
5. To ensure timely and effective implementation of these recommendations, a process should be employed along the lines described in Figure 8 above. Where consensus cannot be reached, the regulator or dispute settlement authority should be empowered to impose an appropriate system.

6. Balancing, Storage and Trading

6.1. Balancing Rules and Imbalance Charges

Balancing rules and imbalance charges together form an essential component of any service offering. Imbalance charges should not be viewed as penalties, but as tariffs for a balancing service provided by the system operator. Imbalance charges that significantly exceed the associated costs therefore conflict with the goals of the Directive. Such costs arise from *net imbalances* on the system, which are typically substantially less than the gross sum of the individual imbalance positions of shippers.³⁵ Excessively stringent balancing rules also conflict with the Directive by discriminating against entrants, whose smaller portfolios of contracts are more difficult to balance. As well as deterring entry, such rules may also inhibit participants from engaging in short-term transactions. They therefore impede efficient system use.

To evaluate whether a given set of balancing rules and imbalance charges are cost-effective and promote the development of a competitive market, it is first important to determine the amount and type of system resources that the TO is reserving for itself to balance the system.³⁶ Such system resources may include linepack, a share of storage or firm receipt and delivery capacity that would otherwise be made available to third parties. Obviously, there is a tension between the amount and type of resources the TO reserves for itself to manage the system, and the amount of capacity made available to third parties to promote competitive access. The resolution of this tension is very much dependent on the design and circumstances of the individual pipeline.

In the U.S. and Canada, pipelines retain some system and storage capacity for balancing purposes while making significant amounts available to third parties. It is rare for U.S. and Canadian pipelines to impose less than monthly balancing requirements. *There are only a few systems that impose daily balancing requirements and none, to our knowledge, require hourly balancing. The use of hourly balancing, as proposed by Gasunie and some others in Europe is the worldwide exception to the rule.*³⁷

³⁵ When many individual shippers have imbalances, some of these will typically cancel each other out. An aggregate system imbalance of just 1% or 2% may therefore arise from individual imbalances as large as 5% or 10%.

³⁶ Linepack tolerance and other engineering parameters must be set according to the principles of the Directive. They should ensure safety and reliability, but should not be excessively stringent. National regulators should examine these parameters against international benchmarks.

³⁷ A recent survey of current or proposed European practice, in a study carried out for Gasunie by PHB Hagler Bailey (reported in *European Gas Markets*, 25 October 1999) provides the following information. SNAM requires monthly balancing, BGE, Transco and Gas Natural require daily balancing, and Gasunie, Distrigaz and possibly GdF require hourly balancing. The survey lists Germany as requiring either hourly or monthly balancing. The subsequently published German VV draft calls for daily balancing.

Before it is accepted that hourly balancing is appropriate, Member States should evaluate whether the TOs have retained sufficient system resources in the form of storage, pipeline capacity and linepack to avoid stringent balancing tolerances. If, for example, storage is not available and linepack is insufficient to handle monthly or daily net system imbalances, then perhaps hourly balancing rules can be justified, as long as any imbalance charges associated with the hourly scheme are cost-reflective and reflect the resources actually required by the system operator to handle net imbalances. If system operators wish to impose hourly balancing requirements, they should be required to provide objective evidence, open to public scrutiny, that less stringent requirements will create problems and that no less burdensome method of resolving those problems can be found. We understand that system operators in a number of Member States, including Belgium, Germany and the Netherlands, have adopted or propose to adopt hourly balancing. They should not be allowed to do so unless they can make their case in an appropriate forum.

Transparency and the effective prevention of abuse are promoted by requiring system operators to demonstrate that balancing requirements reflect genuine system needs, and that imbalance charges are cost-reflective, rather than requiring others to prove the opposite. Alternatively and perhaps preferably, balancing services can be opened up to competition. At a minimum, the operator should be required to recognise the service provided by load aggregators, *i.e.*, intermediaries who nominate on behalf of multiple parties. It may also be advantageous to allow third parties to perform other forms of balancing, virtual and/or physical, and the system operator should be required to make available to such parties any necessary services, including blending and either physical storage or, as discussed below, a “virtual” storage service. From time to time specific security of supply problems may require the operator temporarily to alter or suspend such third party activities. The conditions under which this may occur should be objectively specified and disclosed, and when they arise the operator should provide objective and verifiable evidence. To facilitate third-party efforts to minimise their imbalance positions, TOs should be required to provide timely information as to the periodic status of the system’s linepack, and the net imbalance position of each shipper on the system should be provided to them on a regular basis.

Finally, the same principles apply, *mutatis mutandis*, to the provision of quality conversion services. Such charges may be appropriate in some Member States, such as the Netherlands. However, the TO should be required to prove that the level of charges reflects costs (including an appropriate return on the capital employed).

Conclusions and Recommendations

1. There should be consistency between the amount and type of system resources retained by the TO for system balancing purposes, the stringency of the balancing tolerances required, and the size of any imbalance penalties. TOs should have the burden to demonstrate that such consistency has been achieved, and that their balancing rules and imbalance charges are consistent with the pro-competitive and non-discriminatory principles of the Directive.
2. Outside Europe it is rare for pipelines to impose less than monthly balancing requirements. There are only a few systems that impose daily balancing

requirements and none, to our knowledge, require hourly balancing. The use of hourly balancing, as proposed by Gasunie and some others in Europe is the worldwide exception to the rule.

3. Before it is accepted that hourly balancing is an appropriate protocol, TOs should demonstrate that they cannot avoid stringent balancing tolerances on the basis of the system resources (storage, pipeline capacity and linepack) available to them.
4. Third parties should be allowed to aggregate and/or trade their imbalance positions. TOs should provide regular and timely information to each shipper as to the size of its imbalance position and the coincident linepack status of the system.
5. The same principles developed for balancing services apply, *mutatis mutandis*, to quality conversion services. In particular, the TO should show that any charges for quality conversion are cost-reflective.
6. It will be useful to convene as soon as practicable a meeting of industry participants to discuss and agree the harmonisation of balancing rules and protocols, particularly as they may affect interstate trade.

6.2. Storage

Storage plays several key roles in natural gas systems. In the short term, it is essential for balancing. Storage makes it possible to arbitrage gas prices over a variety of time-frames, most importantly between winter and summer use. The ability to inject gas into storage over the summer and withdraw during the winter significantly reduces peak transmission loads, saving on the need to build pipeline capacity. In mature gas markets similar efficiency-enhancing arbitrages occur over shorter time-frames, for example between weekday and weekend usage. Storage also mitigates the effect of more localised capacity constraints and facilitates exchange and displacement transactions, or “swaps”. Access to storage is particularly important for the development of competition for smaller users. Small users do not have the resources to monitor their gas use closely and purchase gas in fixed increments from a variety of suppliers. Rather, they demand “full requirements” service, which places the obligation on the supplier to meet an often unpredictable and fluctuating load. Particularly in systems with stringent balancing requirements, access to storage is necessary to compete effectively for such customers.

Statement 81/98 of the Council and Commission, concerning Article 2(12) of the Directive, states that access to storage “should only be possible when such access is technically necessary for providing efficient access to transmission and/or distribution networks”. However, all uses of storage can be summarised as facilitating inter-temporal and/or inter-locational arbitrage. In competitive markets, arbitrage opportunities represent unexploited opportunities to conduct trades that benefit all parties. Such trades therefore by definition enhance efficiency. Access to the networks will therefore be inefficient unless storage is made available to all parties.

The ability to access storage represents one of the most significant sources of competitive advantage for a supplier of natural gas. It lowers its costs (through the arbitrages described above), facilitates balancing, and allows it to provide greater flexibility and security of supply to its customers. The refusal of storage access to third parties by a vertically integrated transmission operator will therefore almost invariably prove incompatible with the Directive’s principle of non-discrimination.

A certain amount of storage retained by the pipeline may legitimately be required for operational purposes, but superior access to storage by incumbents would confer a major competitive advantage. Without access to storage, market entry becomes difficult or impossible. The Directive’s principles of non-discrimination and competitive markets therefore require that storage be made available to all users of the system.

Our last conclusion may appear to extend beyond the Directive’s specific requirements concerning access to storage, as outlined above. However, there is no contradiction. The Directive’s specific requirements relate to access to *physical* storage. In contrast, the principles outlined above require incumbents who own storage facilities to provide *services that are economically equivalent to storage* on a non-discriminatory basis. For example, suppose that an incumbent wishes to inject gas into a particular storage facility over the weekend, and withdraw it during the next week. Even if an entrant cannot obtain direct access to the storage facility, the principle of non-

discrimination requires that an economically equivalent service be made available. In particular, the incumbent may choose to provide “virtual storage” by simply accepting gas provided by the third party over the weekend, and delivering it during the following week. The temporary “imbalance” could be handled by the incumbent through line-pack or by trading rather than direct use of the storage facility.

The charge for such services should be non-discriminatory, *i.e.*, they should equal what the incumbent would have charged itself for the service. In particular, *unless the owner has implemented fully open access to storage then it should not be able to profit from the provision of virtual storage*. Such profits would be discriminatory, and would also constitute abuse of a dominant position since the owner would be uniquely placed to provide such a service.

In general many of the considerations listed above in relation to transmission and distribution assets apply equally to storage. A firm storage service with tradable capacity rights should be offered as well as an “on-demand” interruptible service. The same principles for allocating firm transportation capacity also apply to storage. Charges should be justified by reference to transparent tariff models, fixed costs should be allocated to rights in storage capacity, and any “commodity” charges for injections and withdrawals should be based on variable costs only. Harmonisation measures necessary for interconnection and interoperability must be in place, but should if possible arise out of voluntary industry-wide negotiations rather than being imposed from above. Information concerning current and future availability of storage should be publicly available.

In some circumstances, and in relation to certain functions, storage may not be a natural monopoly requiring regulation. For example, in mature gas markets storage may compete with linepack, producer swing and load aggregators in the provision of balancing services. However, there is no substitute for storage in other areas, such as the provision of seasonal arbitrage.³⁸ In relation to those services, the physical characteristics and cost structures of many storage facilities give them natural monopoly characteristics. Finally, whether or not storage is a natural monopoly is not directly relevant to the need for regulation. Regulation is required when market dominance creates the potential for abuse, and this can occur whether or not the market in question involves a natural monopoly.

Ownership of gas storage in Europe is currently highly concentrated. Incumbent pipeline owners also own and control the vast majority of storage facilities, creating the potential for monopolistic abuse. Tariffs for storage should not allow storage owners to earn monopoly profits. Under regulated access, the same principles described above in relation to pipeline tariffs should be applied to determine storage tariffs. Under negotiated access, storage owners should be required to develop their own tariff models that are transparent and objective and applied in a non-discriminatory way across customers. In

³⁸ Where Member States have no storage, the services it provides, such as seasonal arbitrage, are simply not available.

either case, full and effective unbundling of storage may be required if the Directive's principles of non-discrimination and transparency are to be respected.

Conclusions and Recommendations

1. Although the Directive does not explicitly mandate access to storage, it is critical for efficiency, the development of competition, and preventing discrimination. We conclude that, even if direct access to storage is not provided, the principles of the Directive require vertically integrated incumbents to provide “virtual storage” if their affiliates enjoy the flexibility provided by storage assets.
2. The general *service* principles discussed above apply to storage as well, including the offer of tradable firm capacity rights, the allocation of rights, the provision of an “on-demand” interruptible service, and the publication of information.
3. The general *pricing* principles discussed above also apply to storage, including the use of transparent tariff models that meet the “NPV test”, our recommendations concerning asset valuation, the allocation of fixed costs to firm capacity, and the design of any “injection” or “withdrawal” charges to recover variable costs only.

6.3. Trading Mechanisms

Competitive commodity markets are characterised by active trading in liquid and transparent spot and forward markets. Such trading enhances market efficiency, providing important benefits in line with the goals of the Directive. Many of the recommendations in this report will have the effect of promoting trading. This section of the report identifies additional specific measures to further the development of trading mechanisms.

Ownership of physical assets should not be a pre-requisite to trading. Although the Directive does not address this issue explicitly, it is desirable for promoting a competitive gas market and efficient utilisation of the interconnected system. Intermediaries such as traders and brokers lower the cost of trading, and enhance market efficiency by identifying unexploited opportunities for trade. They are of course subject to the same market rules as all other market participants.

Intermediaries provide significant further benefits in bringing liquidity to spot and forward markets. Liquidity is important for a number of reasons: it reduces transactions costs, improves the quality of price information, facilitates economic activity by risk-averse industry participants, and prevents abusive price discrimination by dominant firms. Transactions costs are high in illiquid markets because of the difficulty of finding suitable counter-parties, and of negotiating and valuing contracts. Price signals are scarce, and reflect the specific circumstances of individual contracts. Liquid markets provide a large quantity of directly comparable prices, creating a reliable measure of value. They ensure that forward and derivative contracts are easily available and competitively priced. Risk-averse firms can use such contracts for hedging, resulting in the efficient allocation of risk. Price discrimination is difficult or impossible with liquid markets, both because of the price transparency they provide and because they facilitate resale from customers receiving low prices to those assigned high prices.

Similarly, implementation of the Directive should *not inhibit the formation of appropriate trading mechanisms* such as OTC or centralised exchanges. In mature gas markets, and in other commodity and asset markets, liquidity is provided by intermediaries who participate in OTC and/or exchange-led markets. There is no reason to hinder the activities of such parties in European gas markets.

Our analysis has mentioned swaps in several contexts. First, we identified long-term physical swaps as a feature of the current market environment. Second, in our proposal to require “on-demand” interruptible service and liquid secondary markets, we indicated that each would facilitate the development of short-term swaps as well. Third, we asserted that path-specific transmission tariffs, if efficient, could reduce the need for “swaps” to

improve the efficiency of physical flows.³⁹ We explain swaps and these conclusions in a bit more detail below.

At a very general level, swaps can be distinguished as transactions with significant divergences between physical and contractual flows. For example, for a contract involving the supply of Norwegian gas to France, a large part of the gas supplied by Norway may be consumed in the Netherlands, and replaced in Belgium with other gas from a variety of sources. Similarly, a contract supplying Dutch gas to eastern Germany might be physically supplied by Russian gas, while the Dutch gas physically supplies a customer in western Germany who has contracted to receive gas that is notionally Russian.

As noted above, such transactions are common in European gas markets today. However, the need to negotiate each such transaction on an individual basis inevitably restricts their use to long-term, high-volume arrangements that can justify the level of negotiation involved. The introduction of short-term interruptible service and cost-reflective charges facilitates such arrangements, and allows them to occur without negotiation. In the example above of gas from Norway supplying France, the Norwegian supplier would see the potential to profit by selling its gas in the Netherlands and purchasing new gas in Belgium to fulfil its contractual obligations to supply the French customer. No negotiation would be required, since the swap could be accomplished by trading in the relevant spot and/or forward markets. Provided that transmission is priced in a cost-reflective manner, the market prices will provide an accurate signal of the economic benefit derived from the swap. Liquid spot and forward markets, combined with cost-reflective transmission pricing, therefore facilitate swaps, and are essential to extend swaps to short-term or low-volume transactions.

In designing transmission terms it is essential to ensure that they do not discriminate against swaps. In the second example above, suppose that the Dutch supplier has initially contracted to supply the gas to eastern Germany and nominated to flow accordingly. If at a later date it becomes aware of the possibility of supplying via a swap, then it should be able to change the nomination, up to a reasonable deadline. If the deadline is passed, the swap should still usually be possible, and transmission operators should be required to allow pooling of imbalances to allow the swap to take place without incurring penalties that are unrelated to any cost imposed on the system by the transaction.

Conclusions and Recommendations

1. The Directive's principles of efficiency, competition, and non-discrimination generally support policies designed to encourage financial trading of gas and transportation rights as well as physical trading.

³⁹ Swaps can be thought of as a form of barter arrangement that rectifies inefficiencies in the contractual matching of suppliers and consumers of gas. Path-specific tariffs would create a price system that led to efficient contractual matching *ex ante*.

2. Ownership of physical assets should not be a pre-requisite to trading.
3. To facilitate swaps, changes to nominations should be allowed without penalty up to reasonable deadlines. The pooling and trading of imbalances should also be allowed to help shippers minimise imbalance positions and avoid imbalance charges.

7. Security of Supply, Take-or-Pay and PSOs

7.1. Security of Supply

It is fundamentally incorrect to posit any general conflict between competitive markets and security of supply. Experience in other markets confirms that competitive markets tend to enhance security of supply, and security of supply concerns may safely be entrusted to markets, except in the most unusual circumstances. A number of factors enhance security of supply in liberalised markets. Consumers who place a high value on short-term security of supply are willing to pay for that security, and consequently natural market forces provide it at a cost-reflective price. Moreover, markets have a natural tendency to seek out diverse sources of supply, because differences in price and non-price attributes across alternative sources produce diversification benefits.

The issue of security of supply arises from the EU's dependence on gas from a small number of external sources,⁴⁰ as the Directive recognises (Whereas 12, Article 3(2)). The upstream concentration of ownership may also have significant economic implications for the development of a competitive gas market and cross-border trade. Given this situation, liberalisation may give rise to legitimate questions concerning the future security of supply of natural gas, both in the short and long term. By short-term security of supply we mean the ability to withstand events such as exceptionally cold winters or interruption of a major supply source for weeks or months. Long-term security of supply refers to the long-term availability of natural gas and the associated infrastructure capable of meeting forecast demand without producing large price increases.

However, for the reasons cited above, *these issues do not in general require intervention in the market process*. Particular and exceptional circumstances related to specific market failures may require intervention to assure security of supply. For example, although upstream investments by Western firms should lessen concern in relation to the geopolitical issues relating to external sources of European gas, such investments may not fully resolve that concern. Complementary political action to help ensure long-term security of supply may therefore be justified. All else being equal, however, experience in other gas markets has demonstrated that liberalisation enhances supply security. In particular, minimal intervention in competitive markets is needed to promote short-term security of supply.

It used to be argued that the capital requirements and risk involved in large projects required government intervention, or at least long-term take-or-pay contracts. However,

⁴⁰ European gas supply depends on imports from a relatively small number of countries. Import dependency in natural gas was 40% of total consumption in 1998, and is forecast to rise to around two-thirds of total consumption by 2020 (Communication from the Commission on *Security of EU Gas Supply*, COM(1999) 571 final dated 10.11.1999). Just three countries, Russia, Algeria and Norway supply over 95% of imports, each through a single state-controlled body or enterprise. In this respect, the gas industry in Europe is very different from that in the UK or the US, or from the electricity industry, where the EU has the capacity to meet its demand using a large diversity of sources.

international experience in oil and gas markets over the last two decades demonstrates otherwise. Markets have shown themselves capable of providing finance for even the largest projects. Developed financial and liquid commodity markets can spread the risks of large projects efficiently, avoiding the need for exclusive reliance on governments or inflexible take-or-pay contracts.

For example, the oil industry continues to develop new fields and oil supplies without necessarily relying on long term take-or-pay contracts. Competitive commodities markets facilitate the risk management that supports large investment projects. Developed forward markets provide valuable information on expected future prices. In addition, producers can use the market to hedge, passing on and diversifying risk. The development of the European Union's internal market will encourage such practices in the gas market. More and better information and the opportunity to spread risk will facilitate the financing of large gas projects. In this sense, the market provides its own security of supply.

There is therefore no *general* incompatibility between market liberalisation and security of supply. There should be no automatic presumption that market mechanisms fail to address security of supply concerns. Rather, the general principle should be that distortions to competition on the grounds of security of supply must be justified by the *identification of specific market failures*. The measures adopted should be *demonstrably linked to the market failure identified*, and *objectively shown to be the least distortionary measures possible for solving the problem*. They should be implemented in a *transparent and non-discriminatory* fashion. For example, in the early stages of liberalisation, Member States may:

- Require TOs to provide sufficient delivery capacity for all reasonable gas demand in a particular area; or,
- Oblige TOs to identify back-up supplies, such as a portion of storage that would be used under predefined conditions.

In both examples, the extent of the obligation must be defined in detail, and any required compensation or subsidy provided in a transparent and competitively neutral fashion.

Some parties cite security of supply to argue against access to storage. Although storage is important to security of supply, we do not see how denying access to storage can increase security of supply. We have discussed the importance of storage in fostering competition. Denial of access to storage will create a very real barrier to the development of a competitive gas market in Europe. Consequently, it will diminish commercial incentives to invest in new supply and infrastructure projects, including even new storage facilities. The net effect is likely to reduce security of supply. Although past security of supply concerns in the United Kingdom involved intervention in the storage market, it involved forcing the market to pay for storage capacity that was not demanded independently. Intervention did *not* involve denying storage access to parties who were willing to pay. We find it difficult to see how fully utilised storage assets can provide greater security of supply when monopolised by one entity rather than dispersed among many.

We also note that, even if all storage in Europe were managed as a strategic reserve, to be tapped only in emergencies, its contribution to security of supply would be relatively limited. Total storage volume in Europe is equivalent to only around 50 days' average gas consumption,⁴¹ and storage assets are not uniformly distributed geographically.

Conclusions and Recommendations

1. Liberalised markets tend naturally to enhance security of supply. Security of supply concerns do not justify intervention in market processes except in particular and exceptional circumstances.
2. While take-or-pay contracts may continue to play an important role in European gas markets, they are not required for security of supply in a mature market.
3. Denying access to storage assets does not increase security of supply.
4. In exceptional circumstances market intervention might be justified by security of supply concerns. However, the principles of the Directive require an affirmative demonstration that any such measures are required. The demonstration should:
 - identify a specific market failure that the intervention is intended to redress;
 - demonstrate that the proposed measures are tailored to the problem and minimise market distortions; and,
 - show that the measures will be implemented in the most transparent and least discriminatory manner possible.

⁴¹ *Ibid*, p. 28.

7.2. Take-or-Pay Contracts and Pipeline Access

Historically take-or-pay contracts have played an important role in the development of the European gas industry. Commercial parties undertook investment in gas infrastructure only after securing long-term take-or-pay contracts, guaranteeing the financing of the facilities. Such contracts were formerly essential to finance any major project (or at least were perceived as essential). As shown above, however, a competitive market can manage the risks of major projects, and reliance on take-or-pay contracts is not essential.

With the advent of the liberalised market, existing take-or-pay contracts may become a liability to incumbents whose pipelines could be used by competitors. Article 17 of the Directive recognises this problem by allowing the denial of access to a pipeline where the incumbent would face serious economic and financial difficulties. In this respect, Articles 17 and 25 of the Directive covering the issue of derogation must be rigorously applied. The incumbent must show objectively that its take-or-pay obligations would create serious economic and financial difficulties under open access. Other general principles of the Directive support strict standards for granting derogations. Derogations would contradict the principles of competition, efficiency and development of the single market. Denial of access restricts competition directly, which is essential for increasing the efficiency of the industry and developing liquid markets. We also explained above that denial of access cannot be expected to increase security of supply, so the Directive's concerns with security of supply should not be invoked to soften the standards for take-or-pay derogations.

We conclude that derogations should not be granted unless economic and financial difficulties of a most serious nature are demonstrated. For example, simply to show that open access may threaten a company's desired financial targets, or earning the cost of capital, would not suffice. We propose the following: the transmission operator must demonstrate both that reasonable avenues to renegotiate contracts have already been exhausted, and that open access would threaten financial solvency. Objective evidence such as poor credit ratings or liquidity ratios should be required. Financial solvency is not truly at stake if additional equity capital can be raised, so the company must also demonstrate that this is not an option.

Moreover, the financial liabilities of take-or-pay contracts can be addressed by allowing temporary increases in transportation prices, rather than denying access. This avenue was pursued in the United States when the industry was restructured. We conclude that, even if insolvency is threatened, a derogation should not be granted if a temporary increase in transmission charges could solve the problem. Although this might involve a temporary suspension of the principle of cost-reflective rates, relative to the denial of access it would pose less of a threat to the Directive's primary goal of increased competition.

If a derogation or temporary increase in charges is allowed, the terms should be as non-discriminatory as possible (i.e., they should be incorporated in capacity charges). Any such measure should be for as short a time as possible, with periodic checks of its

continuing need. Ultimately, derogations and other relief should end as past take-or-pay contracts expire.

The Directive does not explicitly address the issues raised by take-or-pay contracts signed either on the eve of liberalisation or in the future. There is no reason to provide derogations for contracts that were signed after market participants could reasonably foresee open access. A supplier who signs such a contract in a competitive market is voluntarily assuming risk, knowing that it may win or lose on the deal. The financial terms of the contract will already provide appropriate compensation for the risk involved. Moreover, the supplier is free to hedge those risks through the use of financial instruments. To permit derogations for future take-or-pay contracts would immunise an incumbent from risks, promoting inefficient behaviour and discriminating against entrants. From our consultations, we learnt that many market participants consider that such contracts will remain one important component of the mature market. However, the choice between take-or-pay and other contractual forms will be one for market participants to make on commercial grounds. Government authorities should not favour, or disfavour, any particular form of contractual arrangement.

Conclusions and Recommendations

1. Take-or-pay derogations should not be granted unless the TO demonstrates that reasonable avenues to renegotiate contracts have already been exhausted, that open access would threaten financial solvency, and that no additional equity capital can be raised. Objective evidence such as poor credit ratings or liquidity ratios should be required.
2. If a derogation or temporary increase in charges is allowed, the terms should be strict. Any such measure should be for as short a time as possible, with periodic checks of its continuing need.
3. Derogations and other relief should end as past take-or-pay contracts expire.
4. There is no reason to provide derogations for contracts that were signed after market participants could reasonably foresee open access.

8. Harmonisation

Our report has identified a variety of areas where harmonisation is required in order to safeguard against discrimination and promote interconnection, interoperability and the creation of a competitive internal market.⁴² We briefly review these recommendations here, and discuss how necessary harmonisation can best be achieved. This section of the report should be read in conjunction with DG Energy's recent report on harmonisation requirements, and the study on interoperability commissioned by the DG last year.⁴³

Our discussions have also stressed the value of promoting harmonisation via voluntary industry action rather than regulatory or legislative *fiat*. Other markets provide useful precedents in this regard. As noted previously, regulators in the United States have encouraged an industry association, the Gas Industry Standards Board ("GISB"), to develop standards on behalf of the industry.⁴⁴ Such a body could play a useful role in determining European standards for natural gas, perhaps in conjunction with the Gas Regulatory Forum.

Standards set by industry bodies must meet the Directive's requirements, including non-discrimination and the promotion of competitive markets. As an essential safeguard against discrimination, *the industry body should reflect the views of all classes of market participants*, including potential third party entrants. Without such safeguards, the body may do no more than provide an *imprimatur* for measures designed to further the interests of incumbents rather than to forward the goals of the Directive. Importantly, GISB has an extremely broad membership, including producers, transporters, distributors, end-users and service providers such as brokers, and its voting structure ensures that its standards represent a broad consensus across the industry.

Our recommendations in this report have included the following elements of harmonisation:

- the definition of firm capacity rights;
- nomination procedures, gas allocation procedures and settlement mechanisms;
- rate-making and asset valuation methodologies when different pipes compete;
- design of charges (approximately harmonised around a 90/10 split between capacity and commodity charges);

⁴² By harmonisation we understand the adoption of a uniform practice or standard for the purpose of facilitating trade and trade-related activities between interconnected systems.

⁴³ Report to the Council and the European Parliament on Harmonisation Requirements, COM(1999) 612 final dated 23.11.1999, and Study on Interoperability of Gas Networks in EU Countries, a study commissioned by the Commission (DG17), 1999.

⁴⁴ Appendix 4 describes the work of GISB in more detail.

- balancing rules and protocols.

Conclusions and Recommendations

1. Where it is required, harmonisation should be promoted via voluntary industry action rather than regulatory or legislative fiat.
2. As an essential safeguard against discrimination, any industry body involved in proposing harmonisation measures should reflect the views of all classes of market participants, including potential third party entrants.
3. Harmonisation is required in a number of areas, including: the definition of firm capacity rights; nomination procedures, gas allocation procedures and settlement mechanisms; rate-making methodology and asset valuation when different pipes compete; design of charges (the fix/variable split); balancing rules and protocols.

9. Next Steps

Our report has suggested two sets of concrete measures to further the implementation of particular parts of its recommendations. These suggestions are in no way intended to be exhaustive. Rather, they focus on areas that require co-ordinated action by European market participants.

First, in relation to the choice of pricing methodology and its implications for cross-border transactions, we recommended the process summarised in Figure 8. Second, in relation to required harmonisation measures, we recommended the voluntary formation of an industry group, with extremely broad membership, to help determine European standards for natural gas, perhaps in conjunction with the Gas Regulatory Forum.

APPENDICES

Appendix 1: Comparison of Existing Tariffs

Table A1: Existing Tariffs in EU Countries

	United Kingdom	The Netherlands	Germany (the "VV")	Spain
Availability?	All customers	Over 10mcm	All customers in principle	Over 5mcm
Published?	Yes All charges are published on the web and in a statement	Yes Most information put on the web – not all	No The VV lays down basic principles only	In part—the Hydrocarbons Bill provides some price and other information
Is there a sector specific, independent regulator?	Yes	No	No	Yes (some time in 2000)
Potential for Discrimination?	Minimal	Gasunie can apply different terms to its own customers	Code is voluntary, may not prevent integrated companies from favouring affiliates	
Balancing regime?	Daily	Hourly	Hourly	Daily
Complexity?	High Advent of entry auctions has added layer of complexity	High Many different types of charges	High 3 different tariff systems proposed	Low
Cost-reflective?	Reasonably so	Insufficient public information to determine at present	Insufficient public information to determine at present	
Access to storage?	Yes	No	No	
Quality conversion?	Included in price	Yes	Uncertain at this time	
Interruptible services?	Yes	Unclear	No	No
Short term contracts?	Yes Daily capacity available	Unclear	Uncertain at this time	No

Appendix 2: Important Distinctions between Gas and Electricity

Issues surrounding the design of cross-border tariffs for electric power in the EU have also been recently raised and are the focus of considerable efforts by the Commission, Member States and the electric power industry. There is some commonality between the gas and electric power industries on these issues: both industries have network characteristics, high fixed and sunk investment costs, and a legacy of state ownership and control of the systems. However, there are also significant differences between the two industries. *These differences significantly affect the design and pricing of transmission services between the two industries, such that in our opinion it would not be appropriate to simply “copy” the arrangements for electric power to the gas industry.* We briefly discuss the four most important distinctions below.

Dispersion of Supply Sources

As discussed, the gas industry in Europe must rely to a great extent on gas supplies from a few large sources of supply outside the borders of individual member states. In contrast, the electric power industry grew up in each country largely with indigenous sources of generated power. While there is some important cross-border wheeling of electric power in the EU, by and large most countries have sufficient local sources of generation to supply their own requirements. Thus, the issues of cross-border trade in electricity are primarily centred around improving the efficiency, depth and interconnectedness of the existing grid to support a single market in electric power.

While consumer choice of electricity supplier across borders will be important, it is arguably not as critical as in gas, where many consumers and new entrants must have transportation access across borders to secure competitive supplies and encourage competition between supply sources. In the gas market environment, harmonisation of system operations, interconnection and tariffs thus takes on very great importance.

Time Element and Storage

There is an important difference in timing of actions that distinguishes gas from electricity. In electricity, controllers must manage the stability and reliability of the grid within the time period of a few seconds, and there are only limited alternatives for electricity storage (e.g., pumped hydro facilities). In contrast, pressure and flow management on gas pipelines can occur over much longer intervals, perhaps hours or days. Gas pipeline linepack provides an inherent buffer that gives gas system operators more flexibility to balance their systems through time. The ability to store gas in underground storage facilities or in above-ground LNG facilities creates further flexibility in gas operations.

These differences between gas and electric power have important implications for harmonisation requirements. Harmonisation in the actions of interconnected control-area

operators becomes extremely important in electric power, whereas in gas there is simply a need to manage the balancing protocols between systems to ensure that there is sufficient gas quality and timing consistency to allow each operator to maintain their system reliability. This creates somewhat more flexibility in gas, for example making it possible to allow customers more discretion in their rights to utilise various receipt and delivery points.

Network Effects

While both gas and electric power transmission systems are networks, the characteristics of the network effects are somewhat different. In electricity, the “flow” of power over wires follows certain physical laws that are different than in gas, giving rise to the phenomenon known as “loop flows”. Because of loop flows, wheeling transactions along one part of the path can have an effect on the availability of transmission capacity along an interconnected path.

While loop flows are endemic to electricity transmission, and will affect the way that transmission capacity access is made available to buyers and controlled by the system operator, there are also network effects in gas. While not “loop flows” per se, it is true that the use of one receipt point into a gas network (or delivery point out) by a consumer or third-party shipper will affect the ability of another shipper to utilise other receipt and delivery points on the network. For gas, this simply means that the amount of transmission capacity that can be made available at any given time will be a function of the planned utilisation of the network. While this is also true in electricity, loop flows make determination of capacity availability significantly more difficult. Loop flows also make the use of “path-based” charging systems in electricity more difficult than in gas.

Quality Issues

A final noteworthy distinction is that there is a wider variety of supply quality issues that must be addressed in gas than in electric power. Gas produced from different fields and wells can have very different energy content, contaminants and water in the gas stream, inert gases, etc. In contrast, most electric power is generated to meet tightly specified characteristics.

While differences in gas quality can be dealt with through physical specification standards, or accounting treatment (as in the case of calorific value), they will all require a certain amount of harmonisation between member states’ systems to permit the interoperability of the European gas grid.

Appendix 3: Summary of Questionnaire Responses

Written responses to our questionnaire were received from 29 participants in European gas markets. Responses were provided by two participants directly to *The Brattle Group* at our offices in London. A broad characterisation of the types of gas market participants who responded is as follows (some respondents fall into multiple categories):

Gas transporters and/or distributors	10
Producers:	2
Storage operators:	1
Traders:	5
Electricity suppliers:	10
Governmental authorities:	7

In the following, we summarise the principal responses to each question, including where there appeared to be a significant difference of opinion among respondents. In appropriate cases we have provided direct quotations without attribution from particular responses.

- 1. Please describe any existing cross-border arrangements for natural gas that you are familiar with (as a direct participant or otherwise). In particular, it would help us to know as much as possible about the nature of services contracted for, the type of negotiation involved, the pricing methodology (in general terms), and the terms on which any ancillary services such as storage are provided.**

Respondents generally indicated that cross-border transactions are currently relatively limited in scope, and principally confined to the UK-continent interconnector (with signs of a market in capacity emerging there), and certain transactions across state borders that are associated with one-off, negotiated and “bundled” long-term contractual arrangements for delivered gas. Examples of the latter that were identified by respondents include:

- Norwegian gas that crosses France is contracted at the Spanish border; transactions on the Magreb-Europe pipeline;

- contracts for the delivery on the DONG (Danish) pipeline specifying the delivery of gas at the Swedish and German borders at fixed prices;
- a contract for the transportation of Algerian gas to Sicily and Centre-South Italy over TRANSMED;
- a contract involving a swap of Russian gas delivered over the TAG (Austria) pipeline for Nigerian LNG over the SNAM network in North Italy.

“In general the costs of Gas Transit through Continental Europe are not transparent. It appears that there may be significant differences between the charging regimes for long term gas transit arrangements and any new agreements that individual companies wish to make to move gas between the grids operated by two different companies or in two different countries”.

One respondent suggested that the focus should not be so much on facilitating interstate transactions, but also transactions between transmission systems (which could also be within-country.)

2. The Gas Directive provides for Third Party Access (TPA) to gas transportation and distribution networks and associated facilities such as LNG and storage capacity under certain circumstances. Please describe the range and nature of services that you believe should be provided.

Respondents identified the following services that should be provided within the framework of TPA. We have indicated in parenthesis the number of respondents mentioning each:

- Firm transportation (6)
- Interruptible transportation (6)
- Storage access (12)
- Reasonable balancing protocols/services (6)
- System, tariff and customer information, including metering (7)
- Variable duration and/or load factor contracts (4)
- Nomination, title tracking and allocation rules and services (3)
- Gas quality conversion and control of physical specifications (8)
- Gasification and regasification (4)
- Network (as opposed to path-based) access (4)
- “Non-discriminatory common carriage” (1)

- “Back-up gas” and “Emergency services” (1)
- “Unbundling” (physical as opposed to accounting-only) (1)

Assorted comments by respondents included:

“At present there is a problem with incumbents refusing access for unbundled contracts. To overcome this, we would like to see greater transparency about available capacity. Balancing requirements should not be excessively onerous as they tend to favour those parties which have access to storage and can therefore constitute a barrier to market entry”.

“In our opinion the European gas market liberalisation can function best in case there is one generally accepted transport tariff system in the European Union market. In case capacity constraints are foreseen, auctioning would make sure that the transport market forces can do their work. For storage, both LNG and underground, a TPA on the basis of auctioning could be developed”.

“...only transportation services are necessary. But it should be clearly defined, what transportation includes. Good examples are the British Network Code or the Gasunie proposal. To facilitate cross border arrangements, the rights and obligations of carrier and shipper on both systems should not be incompatible”.

“Liberalised markets seem to settle on daily, or monthly, balancing. This leaves some balancing costs to be picked up by the TSO, as opposed to the frustration of competition that results from, say, hourly balancing. This frustration of competition is exacerbated when there is no access given to the tools necessary to balance.”

3. In your view, how should the structure and level of charges for TPA be determined? Do any new or special issues arise when the access arrangements relate to cross-border transactions?

Some respondents suggested a revenue or price control approach (but most ignored that issue), with charges for services designed to meet the following criteria (again, numbers in parenthesis indicate the number of respondents mentioning each criterion):

- Unbundling of transmission, distribution and storage accounts (4)
- Non-discriminatory/no cross-subsidies (8)
- Transparent/simple, published tariffs (9)
- Facilitate trading/competition (2)
- Cost-reflective (8)
- Reasonable opportunity for cost/revenue recovery (5)

- Pricing flexibility for interruptible contracts (2)
- Incentive to reduce costs (2)

“We realise that it can be difficult for a set of charges, and the underlying methodology, to meet all these criteria. However, there are enough examples of methodologies that have failed to meet these criteria to allow Member States to ‘fast-track’ the introduction of competition, if they are so inclined, by concentrating on these criteria when designing tariffs”.

“In principle, it is logical to have a 5 or 10-year system, that would recognise operating costs, compensate investments adequately, and that would consider the level of utilisation. As these elements differ by country, there is no need to have a unified tariff system in the European Union”.

“Tariff of transportation should be indexed to inflation only for the portion related to operation and maintenance of the interested lines (generally between 20 and 30% of overall transportation cost)”.

“Pipeline transport is a relatively low risk operation. A return on capital for pipeline owners around the Euro long term bond interest rate plus a surcharge of a couple of 100 basis points is in our opinion acceptable”.

“...cost-efficiency must also be ensured when prices are set. Appropriate for this purpose would be the price comparison concept under competition law, in which the prices of comparable companies are taken as the basis for determining prices”.

Regarding tariff design, respondents suggested a variety of approaches:

- Entry/exit or zonal charges for transmission grids as opposed to distance-related or point-to-point (5)
- Charges should be distance-related (2)
- Two-part tariffs with fixed cost recovery in capacity charge (7)
- Peak-load capacity prices (2)
- No need for an explicit cross-border charge /pancaking should be avoided (9)
- Backhaul flows should command only small fees (2)
- Long-run marginal cost prices (2)
- Allocation by auction in cases of capacity constraint (1)

“One will remember that the gas directive still provides for the possibility of a direct line as an alternative to TPA, for example in systems where transport tariffs do not include a distance related element and penalize non-border transactions”.

“Adding up two charges at each side of the border can not be considered a problem. Pooling or swapping capacities can be arranged by the shippers”.

“If individual transport payment for use of each individual transmission net[work] shall be made, it may result in the fact that the total transport payment will make third-party trade with natural gas unattractive.”

“Complaints are sometimes heard from those trading. Traders tend to give the simplicity of tariff systems a higher priority than fair allocation of the actual cost incurred per customer. The complaints by traders is sometimes that distance related tariffs in transmission tariffs are more difficult to handle and thus automatically in their view a potential barrier. The question at stake here is, whether priority has to be given to an (over)simplified system”.

4. Under the Gas Directive, Member States may choose between “regulated access” and “negotiated access”. In your view, do these systems have different implications for the issue of cross-border transactions?

There were clear differences of opinion amongst respondents on this question, although the vast majority favoured RTPA:

- Regulated access is preferable (15)
- Negotiated access is preferable (4)
- Choice of RTPA or NTPA will have no effect on (or leaves unresolved concerns about) cross-border trade (4)
- Choice will have significant effect on cross-border arrangements (4)

“The greater the differences between charging systems then the more difficult it will be to move gas from one system to another. Regulated access is therefore preferable. However...there should be no charge for simply crossing a border. Whilst negotiated access can more easily be required to allow Shippers’ individual requirements to be considered and responded to, regulated access ensures that no artificial boundaries are put in place through the negotiating process”.

“We suggest that each Member State that chooses NTPA, rather than RTPA, ask gas undertakings to demonstrate that its negotiated prices have actually resulted in non-discriminatory, cost-reflective services”.

“In general negotiated TPA is preferred if negotiations are not dominated by one party, but for commercial and practical reasons one EU regulated access system would be the most effective and efficient”.

“Difficult to see, that a liberalised TPA on EU wide basis could be workable if the rules of the game are not the same in all interconnected markets working under common rules defined by the system operators”.

“...it should not be possible [to] be owner of a shipping company and at the same time of a supply company. At least for cross-border supplies the interior shipping should have a ‘regulated access’ if the shipping subsidiary and the supply subsidiary belong to the same holding”.

“It should be noted that almost all Member States have adopted RTPA for their electricity markets, while those choosing NTPA are required to publish indicative prices and charging methodologies. We see no reason why different arrangements should apply to the gas market. ...Short term trading...would be extremely difficult under NTPA”.

“If the EU is eventually going to be a single market in natural gas, it is very difficult to conceive of some member states with regulated and others with negotiated regimes. At very least the same solution should be established for all cross border transport on a European wide level”.

5. Under the Gas Directive, Member States may impose public service obligations on natural gas undertakings. In your view, will such obligations have a significant impact on cross-border transactions?

There are wide differences of opinion amongst the respondents on this question :

- Member States should not impose PSOs that would restrict the development of the competitive market (7)
- The burden of proof for using a PSO to deny access must lie with the party refusing access (2)
- Imposition of PSOs should be transparent, objective and non-discriminatory (5)
- PSOs will not have any greater implications for cross-border trade than internal transport (1)
- PSOs on gas undertakings will have a significant impact on cross-border transactions (2)
- PSOs have nothing to do with cross-border transactions (1)
- PSOs might affect cross-border transactions, but other factors will dominate (1)

“...we believe that some Member States may be considering imposing PSOs beyond the type of PSOs mentioned in the Gas Directive...We suggest that it is important to stick to the list included in the Gas Directive”.

“Well-designed PSOs should not have a detrimental impact on cross-border transactions, but rather should enhance the level of service provided by TSOs to their customers. However, we have considerable concerns that the development of competition will be constrained by excessive requirements, such as hourly balancing in the Netherlands, and exaggerated interoperability issues such as those that plague the UK-Belgium interconnector”.

“In some systems, access tariffs will include ‘stranded costs’ or costs derived from public service obligations imposed on system operators. We understand that transit tariffs should not reflect these costs if access is not involved to the market of the country that transports the gas”.

“Security of supply arguments should not be used to prevent non-discriminatory access to storage, which is vital in order to meet balancing requirements”.

“A public service obligation might give an excuse to a large monopoly operator to refuse access. Cost will be caused to [imposed on] gas market [regulatory] authorities, if there is often a need to check the legitimacy of such refusals”.

“Security of supply conditions and long term planning requirements surely influence access conditions because of restrictions on available capacity. Apart from this, there is no evident reason why public service obligations should in any way affect cross border tariffs. Here again, there cannot be a workable internal market for natural gas if the member states impose different public service obligations. In the longer term there will have to be some measure of uniformity”.

6. In your view, are there other issues that arise specifically in the context of cross-border arrangements? If so, please describe them.

Many respondents emphasised the importance of creating EU-wide standards for interoperability of systems (pressure, quality, odourisation, etc.). One suggested that the EU should stimulate the construction of interconnection capacity between Member States.

“Maximum flexibility on transport of different gas qualities are essential for cross-border arrangements.... Commercial hurdles like charging too high quality conversion costs should not be allowed”.

“The sharing of responsibility of security of supply between suppliers, importers, gross traders, system operators, retail sellers and customers”.

“Better standardisation is also wished regarding exchange of information and data which is very important when it comes to load balancing”.

“Rejection of access should be justified by the network operator. The reasons could only be based on physical constraints of the network”.

“A major concern is that long term Take-or-Pay agreements may act an artificial barrier to new entrants obtaining access to capacity. ...Any applications for temporary derogations need to be handled in a timely manner and in the meantime access to markets should not be prevented until a derogation is officially granted”.

“In the parallel debate over cross-border trading in the electricity market, the Commission suggested that transmission system operators should set up an organisation that would liase directly with the Commission. The creation of this organisation (ETSO) has enabled the Commission rapidly to move forward the issue of cross-border charging. We suggest that this innovative idea should be applied to the gas industry as well. We recognise that the unbundling requirements of the Gas Directive are weaker than the Electricity Directive. However a “GTSO” would be a significant reinforcement of the continuing push for independent system operators”.

“Cross border transport can be discouraged by differences in the measures taken by member states to ensure that undertakings without sufficient capacity will make the necessary enhancements when a potential customer is willing to pay for them (article 17, paragraph 2 of the European Directive 98/30/EC)”.

“We believe that the aim of the Gas Directive is to promote a single European gas market, not to create fifteen deregulated markets”.

Appendix 4: The Gas Industry Standards Board

This appendix presents a brief description of the work of the Gas Industry Standards Board (“GISB”), a North American industry association that has been closely involved in setting harmonised standards to facilitate access and promote interconnection and interoperability of gas transportation systems. The description is based closely on a GISB publication, “A Concise Guide to GISB”, available on the internet at www.gisb.org.

A Concise Guide to GISB

The Gas Industry Standards Board (GISB) is a nonprofit North American industry association whose mission is “to develop and promote standards to simplify and expand electronic communications, and to simplify and streamline business practices that will lead to a seamless marketplace for natural gas. These standards will assist the natural gas industry in improving customer service, enhancing the reliability of natural gas service and increasing the competitiveness and efficiency of natural gas markets.”

Organization

To ensure that all of the gas industry’s business segments are represented, GISB has five membership categories: distributors (local distribution companies), service providers (brokers, marketers, financial services companies, consultants, law firms, computer firms and other businesses), producers, pipelines, and end users.

GISB’s voting rules ensure that all decisions are the result of a genuine industry consensus. Prospective standards must get at least 17 affirmative votes in the Executive Committee,⁴⁵ and there must be at least two affirmative votes from each segment. Standards must then be ratified by the GISB membership; a 67 percent affirmative vote of those submitting ballots is required for a standard to get final approval. GISB is committed to openness and the broadest possible industry participation. All meetings are open to the public, and GISB’s dues have been intentionally kept at a reasonable level to encourage companies to join.

FERC and GISB

Later in 1995, FERC issued an advanced notice of proposed rulemaking setting a March 15, 1996, deadline for comments “containing detailed proposals for the standard set of information that the commission should require all pipelines to use” in conducting business electronically, “as well as for standard nomenclature and standards for any associated business practices and procedures.” While the commission said it expected GISB “may become a forum through which these industry efforts may be coordinated,”

⁴⁵ The Executive Committee has 25 members, five from each “segment”.

FERC made it clear that it was ready to step in if the industry couldn't accomplish the task itself.

As the result of a substantial effort involving hundreds of volunteers, GISB managed to meet FERC's deadline. On March 15, 1996, GISB submitted 140 proposed standards to the commission, which were accepted by FERC in Order 587, issued on July 17, 1996. Other pro-posed standards followed, the majority of which were adopted by the commission in successor orders.

The development of Order 587 established a unique cooperative relation-ship between FERC and GISB that continues to work to the industry's benefit. It has allowed natural gas companies to have an active role in developing the rules and procedures that will shape the electronic natural gas marketplace. In Order 587, FERC said GISB's standards "are reason-able and represent a considerable step towards the goal of creating a unified pipeline grid." The commission said it is "satisfied that GISB's process is open and fair and that the resulting standards represent broad agreement across all segments of the industry." It also said that GISB's voting procedures "ensure that a broad-based consensus of all industry segments supports these standards."

Electronic Standards

The evolution of the Internet into the principal medium for electronic communications in worldwide commerce led GISB to develop standards for the use of the Internet by the gas industry to transact business. Pipelines are establishing Internet sites, including server sites for electronic interchange of files and World Wide Web pages, to provide information to shippers and other customers. These sites supplement, and will eventually replace, pipelines' electronic bulletin boards (EBBs). These sites allow LDCs and other service requesters to place orders and receive scheduled quantity reports (statements indicating that the gas has been scheduled by the pipeline) electronically. The standards also allow for third-party providers (represented by GISB's services sector) to provide buyers of natural gas, transportation and other services with a "one-stop shopping" capability that will avoid the necessity of communicating with multiple Internet sites in order to complete a transaction.

Standard Short-Term Contract

GISB's model short-term gas sales and purchase contract, adopted in 1996, has received wide acceptance and is now being used throughout the natural gas industry. The acceptance of the contract by the industry was a market-based decision and was not mandated by any regulatory agency. The contract is designed to make natural gas easier to buy and sell by standardizing language and business provisions. The model contract is intended for interruptible or firm transactions of one month or less. It has three parts: the base contract, a general terms and conditions section, and a transaction confirmation. The contract is designed to be adaptable to changing industry conditions and provisions. In addition, GISB's model trading partner agreement, while not a standard, is in wide use

through-out the industry. This agreement is used to describe the communications parameters for the electronic exchange of data by means of the GISB standards.

Capacity Release

Before Order 636, transportation contracts between pipelines (transportation service providers) and shippers prohibited any assignment or sale of the contract to any other shipper. Thus, without specific approval from FERC, the capacity could only be used by the contracting shipper. Order 636 gave shippers the right to sell all or any portion of a contract's rights for all or any portion of its term. The process of selling capacity is known as capacity release.

In a sense, capacity release was what led to GISB and the gas industry's involvement in electronic communications. With the advent of the capacity release market, FERC required pipelines to post openly the deals their shippers were seeking to transact. FERC required each pipeline to establish an electronic bulletin board (EBB) on which released capacity could be posted and offered for sale. Prospective shippers would be able to bid on-line for this capacity.

Industry concerns about the differences among the pipelines' EBBs and the difficulty of dealing with multiple pipelines in order to complete a single deal to transport natural gas led the industry to seek standardization of the capacity release data on EBBs. FERC agreed and assigned GISB the task of standardizing this and other business practices.

Nominations

The nominations process is the way in which those who want to transport natural gas (LDCs and other shippers) request space on interstate pipelines. Nominations are notices to transportation service providers of how much gas the shipper wishes to transport, where the gas will be entering the pipeline system (receipt point), and where it will be delivered (delivery point). GISB's business practices standards provide a procedure and timetable for nominating gas on all transportation service providers, ensuring a seamless process for scheduling transportation service through-out the United States, even when more than one pipeline must be used to get the gas to its destination. The standards also specify how and when transportation service providers should respond to shippers with scheduled quantities, which are agreements on the quantity of gas scheduled to flow. The standards also cover confirmations, which the owners and/or operators of the gas transaction points and facilities involved in the nomination send to the transportation service provider to confirm the quantities and dates specified in the nomination.

GISB standards specify that:

- The standard gas day, basically an accounting period that identifies when gas flows begin, is 9 a.m. to 9 a.m., Central clock time.
- Nominations for the next gas day must be made by 11:30 a.m. Central clock time, with scheduled quantities to be sent to the shipper by 4:30 p.m.

- Any shipper will be able to submit at least one intraday nomination four hours before its gas is scheduled to begin flowing. This will allow the shipper to increase or decrease the amount of gas to be shipped and/or to change the receipt and/or delivery points.
- Receipt and delivery points along pipeline systems will be designated in standardized ways, known as common codes. This is analogous to the standard codes used to identify airports (e.g., IAH for Houston Intercontinental). Common codes will also identify companies involved in gas transactions.
- All nominations, confirmations, and scheduling will be done in standardized energy units—dekatherms in the United States and gigajoules in Canada.

Flowing Gas

GISB standards on flowing gas involve the communication of allocation methodologies and statements, imbalance reports, and measurement statements—information relating to what gas actually flowed to which parties.

To clarify the expectations and responsibilities of all parties prior to gas flow, data on predetermined allocations is exchanged. Predetermined allocations allow the parties to manage the impact of variances between the quantities of gas flowing and the scheduled quantities.

Many different parties can be involved in the movement of natural gas across a particular location. The determination of the entitlement rights of each party of the actual flowing gas moving across the location is accomplished by allocating the actual flow among the parties. Allocations are performed by the operator of the affected location, using the predetermined allocation methodology agreed to by the parties involved. In other words, if less than the expected amount of gas actually flowed, the allocation statement would indicate which parties were allocated what quantity of gas. An allocation statement is used to communicate the allocation information and the methodology used.

An imbalance statement provides data regarding a shipper's actual flow of gas compared to the shipper's scheduled quantity. The statement could indicate that the shipper has received the same amount of gas under his contract as has been delivered under his contract and is thus balanced, or it could indicate an out-of-balance situation in which more or less gas has been received under his contract than has been delivered, or vice versa. Imbalance statements should be provided prior to or along with the invoice.

A measurement information statement provides information on the actual or estimated physical flow moving across a location. It can be used to support other flowing gas or invoicing data requirements.

Invoicing

GISB standards on invoicing are designed to facilitate timely and accurate financial settlements following natural gas transactions, including sales, transportation and storage. These standards focus on communicating charges for services rendered (invoice), details about funds remitted in payment for services (payment remittance statement), and the financial status of a customer's account (statement of account).

Appendix 5: Preventing Discrimination in Capacity Auctions

A major problem arises in considering how to allocate firm capacity rights when the network owner is a vertically integrated incumbent. *Any mechanism involving payment to the owner for the capacity rights enables the owner's affiliate to "hoard" rights because it can pay very large sums for the rights.* Payments from the affiliate to the network are simply internal transfers. The true cost of such payments is therefore not the sum paid, but the difference between the foregone revenue from not selling to a third party and the extra profit from retaining the capacity right. In many circumstances this difference will be much less than the sum paid. Moreover, the affiliate can always later sell the rights on to third parties in the secondary market.

The following auction mechanism is designed to prevent such abuse.

1. The auction follows the standard format of a simultaneous multi-unit auction, *i.e.*, participants submit bids for as many units as they wish to purchase, and can bid different amounts for different units. For example, a bid might consist of "€10,000 per unit for up to 10 units, then €7,000 per unit for up to an additional 15 units". These bids are combined to form a single "bid curve". If there are 100 units of capacity available, then the 100 units are allocated to the 100 highest bids.⁴⁶
2. The prices paid are determined according to a modified "n+1"-bid procedure. Under an "n+1"-bid auction, every winning bidder pays the same price per unit. That price is equal to the 101st bid in the auction. We understand that PreussenElektra recently used this procedure to allocate capacity rights on its international interconnectors.
3. As is common practice in auctions, a reserve price should be set. This price should equal the price determined by the tariff model. The existence of a reserve price protects the network from the risk that other bidders will manipulate the auction.
4. However, we propose a single modification. The difference between the incumbent's winning bids and the 101st bid should be placed in a dedicated fund, rather than being paid over to the network.
5. As a result of this modification **the incumbent effectively "pays as bid"**. It therefore has a disincentive to "hoarding" capacity.
6. The fund can be used to help pay for PSOs or fund capacity expansion. Alternatively, it could be used to reduce the network's other charges, by returning

⁴⁶ If there is a tie for the 100th unit then it can be allocated via a lottery amongst the tied bidders.

it to the network but subtracting the amount involved from the allowed revenue of the network. However, this latter option should not be used until the market is fully competitive. In the transition period, the incumbent is likely to be the largest user of the pipe, and will therefore be the main beneficiary of these reduced charges.

7. This mechanism would not be effective if all the 101 largest bids come from the incumbent. The incumbent should therefore be permitted to bid for no more than a certain fraction of the available capacity. This fraction can be quite large since all that is required is that the 101st bid is a “genuine” one, *i.e.*, reflects the competitive market value of capacity.
8. Under negotiated access, it may not be possible to introduce this scheme initially. However, if problems of abuse arise in the initial allocation of capacity rights, the dispute-settlement authority can insist on the introduction of such a scheme if no other procedure is found acceptable to all parties involved in the dispute.

This scheme has the advantage that the price paid by the incumbent to purchase capacity rights represents a real cost. *It therefore removes the incentive to hoard.*

Non-discrimination

Although the proposed mechanism treats the vertically integrated incumbent differently, that difference does not constitute economic discrimination. Rather it ensures that *the incumbent is subject to the same competitive pressures as all other market participants*:

1. The market price of rights in the secondary market will equal the marginal value of capacity, which is approximately equal to the 101st bid (because participants' bids can be expected to approximate their valuations of each unit). Incumbents can therefore always purchase rights in the secondary market at approximately the price paid by all other participants in the auction.
2. Finally, the difference between the incumbent's bid and the 101st bid will only be large if incumbents value capacity much more highly than other market participants. This situation could arise *either* because the incumbent has a legitimate competitive advantage, such as greater efficiency, *or* because it continues to enjoy monopoly prices downstream, as a legacy of its position pre-liberalisation. There is no particular reason to expect incumbents, who have operated for decades as effective monopoly suppliers without the discipline of competition, to be uniquely efficient. If instead their higher valuation represents the persistence of downstream monopoly, then the effect of this mechanism is simply to take the remaining monopoly profits and use them to reduce the costs of network access. This will speed up the introduction of competition and so remove the alleged discrimination.

Appendix 6: Alternative Methodologies for Regulatory Rate-Making

Table A2 provides an example of historical cost rate-making. The cost of the asset is assumed to be €100, and the asset has a useful life of five years. The “NPV test” is satisfied by calculating capital charges as the sum of depreciation and a competitive return on the net book value of the investment. In the first year, for example, total capital charges are €30, calculated as €20 in depreciation plus an assumed competitive 10% return on the €100 value.⁴⁷ In the second year, total capital charges of €28 are explained by €20 in depreciation plus a 10% return on the €80 net book value of the asset. The total present value of these charges over five years, when discounted at the competitive rate of return, is exactly €100.

Table A2: Historical Cost Accounting

Cost of Capital [1]		10%				
Year		1	2	3	4	5
BOY Asset Value	[2]	100	80	60	40	20
Depreciation	[3]	20	20	20	20	20
EOY Asset Value	[4] [2]-[3]	80	60	40	20	0
Rate of Return	[5] [1]	10%	10%	10%	10%	10%
Return on Capital	[6] [2]x[5]	10	8	6	4	2
Total Capital Charges	[7] [3]+[6]	30	28	26	24	22
Present Value	[8]	100				

[1]: Assumed.

[2]: Initial investment of 100. Thereafter, $[4]_{t-1}$

[3]: Fixed amount to depreciate by year 5.

[8]: PV of revenues in [7], discounted at [1].

Table A3 provides an example of “trended cost” rate-making using similar assumptions. An inflation rate of 5% is applied to the asset’s original cost over the relevant time period. Inflation generates an annual “write-up” in the value of the asset, and produces higher depreciation charges than historical cost rate-making. To satisfy the NPV test, the write-up must be applied as an offset to the depreciation charge in each year. In the first year, the write-up of €5 must be subtracted from the €21 depreciation charge to produce a net figure of €16. In conjunction with a 10% return on the initial €100 asset value, the total capital charge is €26. This is lower than produced by the historical

⁴⁷ Here the 10% is a pre-tax return. The calculations shown in this section are all performed on a pre-tax basis. Alternatively, it is possible to estimate a required after-tax return on capital, and ensure that after-tax returns provide the requisite return. Some regulators attempt to model the tax regime in detail, taking into account the particular circumstances of the regulated firm, while others use a simplified picture with a single corporate tax rate that is assumed to apply to the firm.

cost methodology, but the “trended cost” procedure generates higher charges in subsequent years. Over the life of the investment, the present value of charges is exactly €100.

Table A3: Trended Costs

Cost of Capital	[1]	10%					
Inflation	[2]	5%					
Year		1	2	3	4	5	6
BOY New Asset Cost	[3]	100	105	110	116	122	128
% of Useful Life Remaining	[4]	100%	80%	60%	40%	20%	0%
BOY Asset Value	[5] [3]x[4]	100	84	66	46	24	0
Annual Write Up	[6] [3] _{t+1} -[3] _t	5	5	6	6	6	
Cumulative Depreciation	[7] [3]-[5]	0	21	44	69	97	128
Annual Depreciation	[8] [7] _{t+1} -[7] _t	21	23	25	28	30	
Rate of Return	[9] [1]	10%	10%	10%	10%	10%	
Return on Capital	[10] [5]x[9]	10	8	7	5	2	
Total Capital Charges	[11] [8]+[10]-[6]	26	26	26	27	27	
Present Value	[12]	100					

[1]: Assumed.

[2]: Assumed.

[3]: Initial investment of 100. Thereafter, $[3]_{t+1} = [3]_t \times (1 + [2])$.

[4]: Fixed amount to depreciate by year 5.

[12]: PV of revenues in [11], discounted at [1].

This is the method used in the United Kingdom for the British Gas pipeline system, although the published calculations are cast in real terms rather than nominal ones, and the inflation write-up therefore does not appear explicitly. Table A4 shows that recasting the analysis in real terms produces identical capital charges over time.

Table A4: OFGAS Methodology

Cost of Capital	[1]	10%				
Inflation	[2]	5%				
Year		1	2	3	4	5
BOY Asset Value (Real)	[3]	100	80	60	40	20
Depreciation (Real)	[4]	20	20	20	20	20
EOY Asset Value (Real)	[5] [3]-[4]	80	60	40	20	0
Real Rate of Return	[6]	5%	5%	5%	5%	5%
Real Return on Capital	[7] [3]x[6]	5	4	3	2	1
Total Capital Charges (Real)	[8] [4]+[7]	25	24	23	22	21
Total Capital Charges (Nominal)	[9]	26	26	26	27	27
Present Value	[10]	100				

[1]: Assumed.

[2]: Assumed.

[3]: Initial investment of 100. Thereafter, $[5]_{t-1}$

[4]: Fixed amount to depreciate by year 5.

[6]: $(1+[1])/(1+[2])-1$.

[9]: $[8] \times (1+[2])^{\text{year}}$

[10]: PV of revenues in [9], discounted at [1].

Table A5 provides an example of “economic depreciation”. Here regulation is designed to reproduce the price pattern that would prevail in equilibrium in a competitive market, *i.e.*, prices would stay constant in real terms. In our example, which assumes that the prevailing rate of inflation is 5%, this gives annual 5% increases in nominal terms.

The depreciation allowed under the “economic depreciation” methodology is derived implicitly. One begins by finding a schedule of prices that is constant in real terms over time, and satisfies the NPV test.⁴⁸ Depreciation in each year is then derived by taking the desired total capital charges, and subtracting a 10% return on the investment’s net book value.

When this methodology is applied in a situation where volumes are expected to increase over time it may produce depreciation that is less than zero in one or more years. However, total depreciation charges over time will be equal to the original cost of the asset.

⁴⁸ From a technical point of view, this is achieved by finding the first year total capital charge which, when escalated at 5% per year, produce a present value of €100. Modern spreadsheet software makes this a simple procedure.

Table A5: Economic Depreciation

Cost of Capital	[1]	10%				
Inflation	[2]	5%				
Year		1	2	3	4	5
Total Capital Charges	[3]	24	25	27	28	29
Present Value	[4]	100				
BOY Asset Value	[5]	100	86	69	50	27
Rate of Return	[6] [1]	10%	10%	10%	10%	10%
Return on Capital	[7] [5]x[6]	10	9	7	5	3
Depreciation	[8] [3]-[7]	14	17	20	23	27
EOY Asset Value	[9] [5]-[8]	86	69	50	27	0

[1]: Assumed.

[2]: Assumed.

[3]: Year 1 set to return PV of 100. Thereafter, $[3]_{t-1} \times (1 + [2])$.

[4]: PV of revenues in [3], discounted at [1].

[5]: Initial investment of 100. Thereafter, $[9]_{t-1}$

Finally, Table A6 provides an example of “depreciated replacement costs”. The replacement cost of the asset is assumed to follow an irregular pattern over time. As with the “trended cost” methodology, the “NPV test” is satisfied as long as any increases in the asset’s value are deducted in calculating total capital charges for the year. Note that, if the replacement cost of the asset were assumed to increase at a steady 5% per year, then the “depreciated replacement cost” methodology would be identical to the “trended cost” methodology.

Table A6: Depreciated Replacement Cost

Cost of Capital		[1]	10%					
Year			1	2	3	4	5	6
Inflation		[2]		0%	6%	0%	10%	2%
BOY New Asset Cost		[3]	100	100	106	106	117	119
% of Useful Life Remaining		[4]	100%	80%	60%	40%	20%	0%
BOY Asset Value		[5] [3]x[4]	100	80	64	42	23	0
Annual Write Up		[6] [3] _{t+1} -[3] _t	0	6	0	11	2	
Cumulative Depreciation		[7] [3]-[5]	0	20	42	64	93	119
Annual Depreciation		[8] [7] _{t+1} -[7] _t	20	22	21	30	26	
Rate of Return		[9] [1]	10%	10%	10%	10%	10%	
Return on Capital		[10] [5]x[9]	10	8	6	4	2	
Total Capital Charges		[11] [8]+[10]-[6]	30	24	28	23	26	
Present Value		[12]	100					

[1]: Assumed.

[2]: Assumed.

[3]: Initial investment of 100. Thereafter, $[3]_{t-1} \times (1 + [2])$.

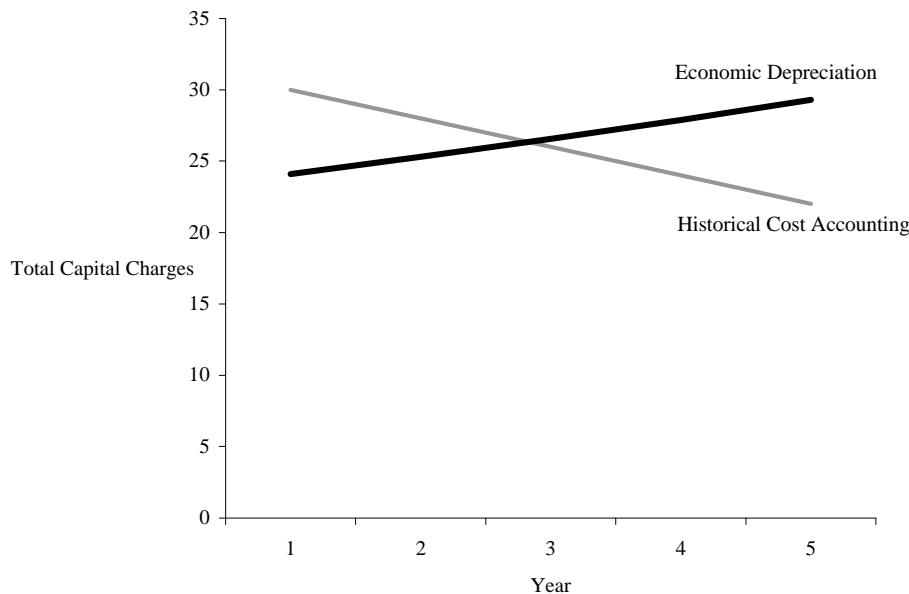
[4]: Fixed amount to depreciate by year 5.

[12]: PV of revenues in [11], discounted at [1].

In some cases, owners of infrastructure have advocated charges based on replacement costs without recognising asset write-ups as an offset against capital charges. The argument is that “efficiency” requires prices that provide a competitive return on *new* assets. This methodology can provide a present value of capital charges that exceeds the initial cost of the investment. The argument that efficiency somehow requires such prices is mistaken. Efficient markets in equilibrium follow the properties of “economic depreciation” which, as shown in Table 6 above, is not anticipated to exceed the “NPV test”. Rather, financial economists view any pricing methodology that can be expected to exceed the “NPV test” as an exercise of market power.

Owners of infrastructure have also attempted at times to switch from one rate-making methodology to another. Care must be taken to prevent the switch from generating windfall gains or losses. An example is provided at the end of this appendix.

Figure A1: AlternativeTariff Methodologies



Source: Tables A2 and A5

In addition to meeting the “NPV test” for basic services, *the choice of tariff methodology should seek to avoid economic distortions in the use of different pipelines or the construction of new capacity.* The figures and tables above illustrate the potential for methodologies to provide different capital charges for assets of different ages. For example, imagine that a pipeline regulated pursuant to “historical costs” competes with a pipeline regulated pursuant to “economic depreciation”. Figure A1 illustrates the tension: in the first few years the “economic depreciation” pipeline will have lower charges, but in the last few years the “historical cost” one will have lower charges. If the two pipelines

compete by serving the same customers or gas supply sources, then the discrepancy in charges can provide distorted economic signals. Users will be motivated to use the “economic depreciation” pipeline more heavily at first, and then switch to the “historical cost” one.⁴⁹ In addition, the tariffs of the “historical cost” pipeline in its last few years may be so low as to prevent the economic construction of a new pipeline using either the “historical cost” or “economic depreciation” methodology. Such distortions can be avoided by the use of “economic depreciation”. Greater discretion over the selection of tariff methodology exists for those pipelines that do not face competition from other pipelines, or where the decision to add new capacity does not depend on the charges of existing pipelines.

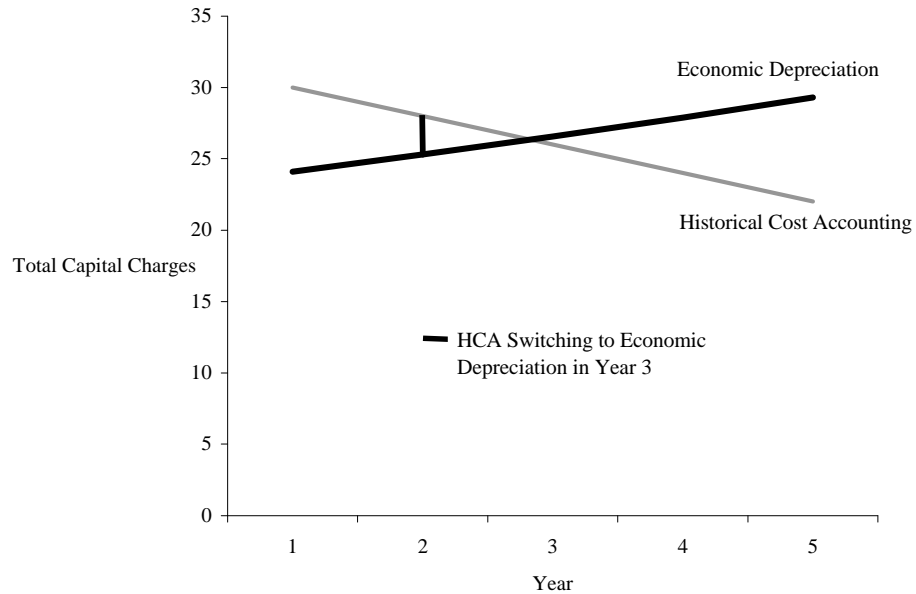
Of the various methodologies described above, *the “economic depreciation” approach has several advantages*. First, if the methodology is designed to track inflation in pipeline construction costs over time, then it has the merit of producing charges that should not vary between old and new pipelines. Second, it can be designed to produce charges that stay stable even as throughput changes over time. For example, if low volume is anticipated in the first few years of a pipeline’s life, then the “economic depreciation” method can be designed to ensure that those volumes do not pay higher prices. Rather, the methodology can ensure that charges per unit volume remain steady in inflation-adjusted terms over time, by postponing a portion of capital recovery until higher volumes materialise. Prices in competitive markets behave similarly. We note that other techniques, such as a five-year “RPI-X” system, can also contribute to steady prices over time. The regulatory formula adopted in the most recent British Gas price control provides an example.

Switching Rate-Making Methodology

Care must be taken when switching rate-making methodology to avoid generating windfall gains or losses. Figure A2 shows how the capital charges produced by historical cost rate-making decrease over time relative to those associated with “economic depreciation”. Therefore, if historical cost accounting is used to determine pipeline charges for the first two years, and the system then switches to “economic depreciation”, the pipeline owner receives a windfall. Such a switch allows it choose “the best of both worlds”, using each system for the period when it produces the highest charge. The net effect is that total charges over the life of the pipeline are too high, and the pipeline owner can expect to earn a profit that is in excess of its cost of capital.

⁴⁹ If capacity is traded on secondary markets then the market price of capacity in the two pipelines will be equalised. However, this will not prevent the misallocation of resources, which will occur in the primary market. The primary market will see excess demand for capacity on the cheaper pipeline, which will therefore be fully booked, while demand for capacity on the more expensive pipeline will be just sufficient to serve the unfulfilled demand for the cheaper pipeline.

Figure A2: Switch in Revenue Streams - PV > 100



Source: Table A7

In this case total capital charges have a present value of €108 on an initial investment of €100, as shown in Table A7. Any switch in methodology must therefore be factored in to the regulatory calculations to avoid such windfalls.

Table A7: Inappropriate Switch from HCA to Economic Depreciation in Year 3

Cost of Capital [1]		10%				
Year		1	2	3	4	5
Historical Cost Accounting [2]	Table A2	30	28	26	24	22
Economic Depreciation [3]	Table A5	24	25	27	28	29
Total Capital Charges [4]		30	28	27	28	29
Present Value [5]		108				

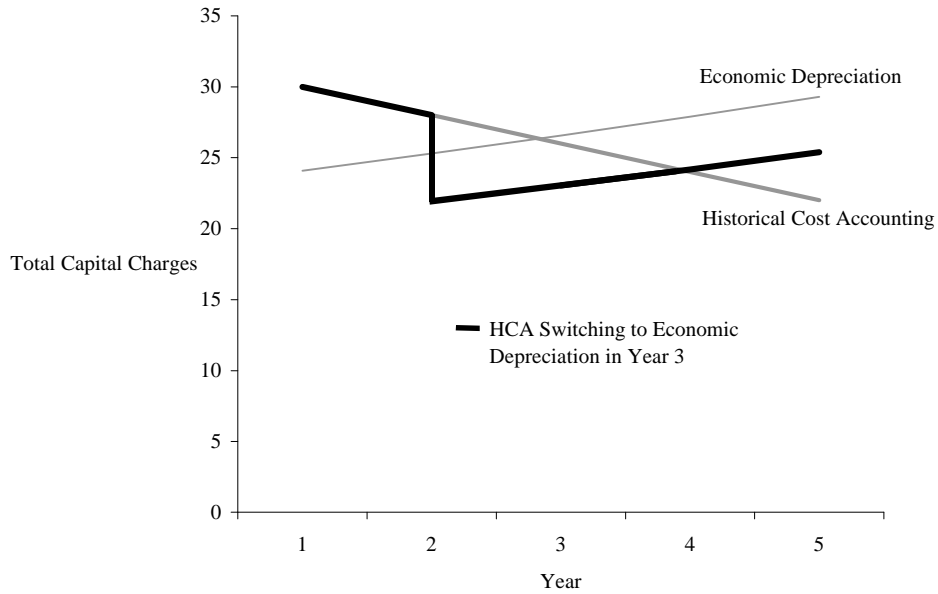
[1]: Assumed.

[4]: Years 1 and 2, row [2]. Thereafter, row [3].

[5]: PV of revenues in [4], discounted at [1].

In practice this is achieved by ensuring that any new methodology takes as a starting point the depreciated net book value of the previous methodology. An “NPV neutral” switch is demonstrated in Figure A3, and the underlying calculations given in Table A8.

Figure A3: Switch in Revenue Streams - PV = 100



Source: Tables A7 and A8

Table A8: Appropriate Switch from HCA to Economic Depreciation in Year 3

Cost of Capital	[1]	10%				
Inflation	[2]	5%				
Year		1	2	3	4	5
BOY Asset Value	[3]	100	80	60	43	23
Depreciation	[4]	20	20	17	20	23
EOY Asset Value	[5] [3]-[4]	80	60	43	23	0
Rate of Return	[6] [1]	10%	10%	10%	10%	10%
Return on Capital	[7] [3]x[6]	10	8	6	4	2
Total Capital Charges	[8]	30	28	23	24	25
Present Value	[9]	100				

[1]: Assumed.

[2]: Assumed.

[3]: Initial investment of 100. Thereafter, $[4]_{t-1}$

[4]: Years 1 and 2: Fixed amount to depreciate by year 5. Thereafter, $[8]-[7]$.

[8]: Years 1 and 2: $[4]+[7]$. Year 3: Set to return PV of 100. Thereafter, $[8]_{t-1} \times (1+[2]_t)$.

[9]: PV of revenues in [8], discounted at [1].