COMMISSION
OF THE EUROPEAN
COMMUNITIES

DIRECTORATE-GENERAL FOR ENERGY

Study on the ADVANTAGES AND DRAWBACKS FOR THE EUROPEAN COMMUNITY OF THE INTRODUCTION OF A SYSTEM OF 'COMMON CARRIER' FOR THE TRANSPORT OF NATURAL GAS

Final report - Main volume

C&L
Belmont
in association with
Prognos AG

January 1989

STUDY ON THE ADVANTAGES AND DRAWBACKS FOR THE EUROPEAN COMMUNITY OF A SYSTEM OF "COMMON CARRIER" FOR THE TRANSPORT OF NATURAL GAS

MAIN VOLUME

C&L BELMONT
in association with
Prognos AG

January 1989

STUDY ON THE ADVANTAGES AND DRAWBACKS FOR THE EUROPEAN COMMUNITY OF THE INTRODUCTION OF A SYSTEM OF "COMMON CARRIER" FOR THE TRANSPORT OF NATURAL GAS

Contents - Main Volume:

I INTRODUCTION

Background to the study

1.1 This study for the Directorate General for Energy (DG XVII) of the European Commission regarding a possible "common carrier" system for the transport of natural gas within the European Community is placed within the overall context of the Commission's move towards completing the internal market by 1992.

1.2 COM(85) 310, the Commission's White Paper to the European Council on completing the internal market, provided the overall framework for removing physical, technical and fiscal barriers to trade within the Community. Although the proposals envisaged in the timetable annexed to the White Paper did not specifically address the energy sector in any great detail, a number of more general proposals for Council Directives are likely (if approved) to have a significant impact on European energy markets. These include proposal COM(87) 321 on the approximation of VAT rates and, in particular, COM(87) 327 on the approximation of the rates of excise duty on mineral oils. Moreover, and perhaps most importantly of all, the White Paper established a general strategy for harmonisation and the removal of barriers to internal trade, including key issues such as the application of Community Law in the field of competition policy and state aids.

1.3 More recently, a Commission Working Document entitled "The Internal Energy Market" (COM(88) 238) has been produced by DG XVII. This document focuses specifically on the implementation of the 1985 White Paper and the application of Community Law in the energy sector. It does not, at this stage, attempt to prescribe solutions but presents a comprehensive inventory of possible barriers to trade in each major form of energy, including natural gas, and identifies the priority areas for action to remove the most significant barriers. In the case of natural gas, the priorities identified in COM(88) 238 include the following:

(a) greater price transparency for non-tariff sales, especially in the United Kingdom and West Germany;
(b) harmonisation of taxation on energy;

(c) increased interconnection and integrated operation of the European gas pipeline network; and

(d) the possibility of "common carrier" third party access to the grid in return for a reasonable carriage charge - either for other gas transmission and distribution undertakings only or for industrial customers as well.

1.4 The present study therefore stems from one of the key priority areas identified in COM(88) 238. Its principal objectives are to identify the conditions under which an effective common carriage system for natural gas might be introduced at the Community level and to identify the advantages and drawbacks which such a system could have for Community gas producers, utilities, consumers and the interests of the Community as a whole.

Definition of common carriage

1.5 It may be helpful at the outset to identify what is meant by a common carriage system for natural gas. By "common carriage", we understand some form of statutory obligation on gas pipeline owners to transport gas for third parties in return for a reasonable carriage charge. At present, there is some third party use of natural gas pipelines within the European Community, but this is almost entirely confined to use by agreement between gas utilities. A common carriage system would differ from the present system in that third parties - whether other gas companies or large industrial consumers - would have a legal right, under certain circumstances, to have their gas carried through others' pipelines. In turn, the pipeline owners would not generally be able to refuse to provide a transportation service, subject to the pipeline capacity being available.

1.6 In practice, a natural gas common carriage arrangement may well involve a number of other elements besides the payment of a carriage charge in return for transportation. These could include:

(a) provision of a storage service to convert a high load factor bulk supply into a low level load factor supply to the consumer;

(b) provisions regarding the construction of additional pipeline capacity, where required, in return for reasonable payment;

(c) provision of a "back-up" supply service to cover the shipper against an interruption to his gas supply;

(d) provision for gas transportation which is either "firm" or "interruptible" (at the option of the pipeline owner), as the case may be; and

(e) provisions regarding priorities as between the shipper and the pipeline owner's own customers, in circumstances where pipeline capacity is limited.

1.7 Transportation of natural gas for third parties is now well developed in the United States, though in this case much third party transportation takes place under Federal Energy Regulatory Commission (FERC) Order 436, which is voluntary on the pipeline owners. In other words, there is no statutory obligation as such to carry gas for third parties in the US. A common carriage obligation has existed in the United Kingdom since 1982 and was modified in 1986, though actual third party use of the British Gas system has yet to take place.

Structure of the study report

1.8 Sections II-IV of the report are essentially concerned with the environment into which gas common carriage might be introduced. In Section II, we set out the context for our evaluation of a possible gas common carriage system, in terms of the European Community's energy objectives as they relate to the gas sector. We focus particularly on those objectives which might be affected - either positively or negatively - by the development of common carriage. Section III then deals with the current gas supply situation in the Community, with a focus on those features which either constitute barriers to internal trade in natural gas or would influence the impact of a common carriage system. In Section IV, we review the legislative, regulatory and administrative situation within the Community as it affects the internal market in natural gas. As well as identifying barriers to internal trade, the report also highlights any existing legislation (in the UK and elsewhere) which provides for the possibility of common carriage in natural gas. In Section IV, we also look at the relevant provisions of the Treaty of Rome, the existing powers of the European Commission and its administrative procedures as these apply to internal trade in natural gas. We then discuss the legislative and regulatory framework for common carriage in the United States, which is of interest because of the uniquely widespread use of third party gas transportation in that country.

1.9 Having examined the policy, gas market and legislative environment, we then turn in Sections V and VI of the report to specific common carriage issues. Section V addresses the key conditions for the effective implementation of a common carriage system at the Community level, including the framework of gas carriage obligations and charges, pipeline capacity issues and the corresponding regulatory regime. In Section VI, we then turn to the impact of such a system on gas consumers, the gas industry within the Community and the advantages and drawbacks of common carriage for the Community as a whole.

1.10 Although the US gas supply situation is very different from that prevailing in the Community, the development of third party gas transportation there is nevertheless of considerable interest and is summarised in Appendix A to the report. Appendix B contains a glossary of technical and other gas industry terms used elsewhere in the report and in Appendix C we acknowledge the assistance of many gas utilities, oil companies, energy consumer associations and other bodies with whom we have had the benefit of discussions during the course of the study. For ease of reference, the study terms of reference are set out in Appendix D.

II THE COMMUNITY'S ENERGY OBJECTIVES

Introduction

2.1 The assessment of possible advantages and drawbacks of a gas common carriage regime for the Community as a whole must be seen in the context of the Community's energy policy objectives, as they relate to the natural gas sector. On 16 September 1986, the European Council adopted new Community energy policy objectives for 1995 and convergence of the policies of the Member States (O.J.E.C. No C241). The Council Resolution highlights the fact that "adequate and secure availability of energy on a satisfactory economic basis remains a prerequisite for the pursuit of the economic and social objectives of the Community and of Member States." Perhaps the central theme of this document is the need to reduce the vulnerability of the Community to a possible tightening of the oil market and sudden price hikes of the kind experienced in 1973-4 and again in 1979-80. Thus "priority should be given.... to containing energy consumption to a greater extent and to restricting the share of oil and..... to ensuring that the level of dependence on imported energy, and in particular imported oil, is not unreasonable." The Commission therefore points out that "efforts must be made and, if necessary, reinforced... in order to reduce to a minimum the risk of tension at a later date on the energy market and in particular on the oil market."

Energy diversification

2.2 As a consequence, diversification of energy supplies and the further development of the Community's own energy resources are of considerable importance in meeting these objectives. Specific performance targets for 1995 are to reduce the total oil share of energy consumed in the Community to 40% and to maintain the net oil import share of total energy consumption at less than one-third. The latter objective was already achieved in 1986, with a 33% oil import share for the 12 Member States as a whole, but the total oil share was still significantly above the target level at 47%. Apart from the UK (which is a net oil exporter), the net oil import share varied from 39% in Denmark through to 82% in Portugal and, as the UK's net oil exports are likely to decline in the longer term, there is clearly going to have to be further significant diversification away from oil use if the Community's targets are to be achieved.

2.3 The key energy objectives with a direct bearing on the natural gas sector must therefore be seen within this overall policy framework of diversification in energy supply. A central Community objective for the sector is thus "to maintain the share of natural gas in the energy balance on the basis of a policy aimed at ensuring stable and diversified supplies." The current natural gas share of gross energy consumption varies widely across Member States, as shown in table 2.1 below:-

Table 2.1 : Share of natural gas in gross energy consumption (%), 1986

NL	UK	I	D	Irl	B	F	L	DK	Esp	He	P	EUR-12
44	23	21	15	15	14	12	10	6	3	0	0	17

In the light of plans to develop new or considerably expand existing gas industries in Greece, Portugal, Denmark and Spain, together with a growing gas share of household and other small user markets elsewhere in the Community, the maintenance of the overall existing gas share would appear to be a very modest target for 1995. Nevertheless, it is clear that the Commission envisages a continuing and important role for gas in a diversified mix of energy supplies for the Community.

Indigenous gas production

2.4 A further important element in the objectives for maintaining secure and diversified energy supplies is the development of policies aimed at "continuing and, if need be, stepping up natural gas exploration and production in the Community." Currently, nearly two-thirds of total natural gas consumption in Member States is covered by indigenous gas production from within the Community. Almost half of this indigenous production takes place in the Netherlands, with a further 30% or so produced in the United Kingdom. Nearly half of Dutch gas production is exported, principally to West Germany, France, Italy and Belgium, while UK gas output is entirely devoted to consumption within the UK itself. Smaller but nevertheless significant indigenous production takes place in

West Germany (almost all onshore in Niedersachsen), Italy (onshore in the Po Valley and increasingly offshore in the Adriatic) and France (virtually all from the Lacq area in South West France). The pattern of indigenous gas production in the Community in 1987 is shown in table 2.2 below:

Table 2.2 : Indigenous gas production in the Community, 1987

	NL	UK	I	D	Fr	Others	EUR-12
Share of EC gas production	44%	30%	11%	10%	3%	3%	100%
Proportion of home gas consumption	167%	79%	41%	28%	13%	32%	64%

Of the smaller gas consuming countries in the Community, Denmark and the Republic of Ireland are currently a net exporter and self-sufficient respectively, while Belgium and Luxembourg are entirely dependent on imported gas supplies and Spain also relies mainly on gas imports to meet its needs.

2.5 Projections made by the European Commission late in 1986 (COM(86) 518) suggest that the total amount of indigenous gas production in the Community is unlikely to change very much between now and the end of the century. A somewhat lower level of contracted gas exports is likely to mean reduced production in the Netherlands and output from Lacq in France is expected to decline significantly. In Italy and West Germany, the amount of indigenous gas production may be little changed from today's levels while increases are expected in Denmark and Spain. The major uncertainty perhaps lies in the United Kingdom, where significant additional supplies have still to be contracted to meet demand through to the end of the century. While there are probably more than adequate indigenous gas reserves in place, it is somewhat less certain whether sufficient fields can be developed economically on the timescale required to meet demand at prices British Gas or other potential buyers would be willing to pay. Although the Commission's projections show the UK as entirely supplied by indigenous gas in 2000, it appears to us at least as likely that there could be a significant market share for imports, of which Norway is by some way the most probable source. Overall, the growing demand for gas in the Community is likely to be such that dependence on imports from non-member states could rise from 37% in 1987 to around 40% in the 1990s and yet higher in the first decade of the next century.

Gas supply security

2.6 One of the principal policy concerns of the European Commission in the natural gas sector is the security of the Community's supplies and, in particular, its vulnerability to the possibility of a major supply interruption. Although the share of overall Community gas use accounted for by imports from non-member states is only around one-third, the proportion of supplies obtained from outside the Community is much higher for some individual Member States. The "third country" share of total 1987 gas consumption, for example, was around 45% in West Germany and in Italy, 55% in Belgium and nearly 80% in France and Spain. These non-Community gas imports typically account for some 5-10% of total energy consumption in those countries. Significant increases in third country market share are expected over the next few years in Belgium, Italy and France, as a result of somewhat reduced Dutch gas export volumes, growing gas demand and declining indigenous production in the case of France. Non-member states' gas exports will probably account for some 60-65% of total gas consumption in Belgium and Italy in the 1990s and for over 80% of gas used in France. Only in Spain is a significant decline in the non-EC gas share of the market expected to take place, as indigenous Spanish gas reserves are further developed.

2.7 At present, there are three main non-EC exporters of natural gas to the Community - Algeria, Norway and the USSR, who in 1987 accounted for 10%, 12% and 14% respectively of total natural gas use in Member States. There have recently been significant increases in Soviet gas exports to West Germany, France and Italy and recent contractual arrangements suggest further changes in the 1990s and beyond. For example, Norway has concluded large new export contracts for gas from the Troll and East Sleipner fields with a consortium of buyers from Belgium, France, the Netherlands and West Germany and has signed a smaller contact for exports to Enagas of Spain. In 1988, Greece has concluded an LNG import contract with Algeria and is also reported to have agreed price terms for supplies of pipeline gas from the USSR. Portugal also has plans to import LNG in the 1990s and Algeria is a possible source of these supplies. Although other potential exporters (such as Nigeria) may begin to enter the picture from around the turn of century, the three exporting countries who are currently the Community's major sources of non-indigenous supplies are likely to continue to dominate the third country share of the EC gas market for many years to come. In particular, the USSR is projected to achieve a slightly higher market share than in the mid 1980s - perhaps 15% of total Community gas consumption by around the turn of the Century. To put this in context, the largest non-EC supplier of gas to the Community is unlikely to account for more than about 3-4% of total energy use.

2.8 Most Member States also seek to ensure a balanced, diversified portfolio of gas supply sources, in order not to be unduly reliant on any single non-EC supplier. Table 2.3 below shows all the projected supply sources for each Member State which are expected to account for more than 10% or so of total gas supplies around the turn of the century.

Table 2.3: Projected major sources of gas supply by Member State, 2000

	Community	Non-EC
B:	NL	Alg, Nor
D:	Indig, NL	Nor, USSR
DK:	Indigenous	Nor(?)
Esp:	Indigenous	Alg, Nor, Libya
F:	NL	Alg, Nor, USSR
He:	-	Alg, USSR
I:	Indig, NL	Alg, USSR, Nor(?)
Irl:	Indigenous	-
L:	NL	-
NL:	Indigenous	Nor
P:	-	Alg(?)
UK:	Indigenous	Nor(?)

Given the long-term nature of most gas trading within and around Western Europe, most of these supplies are already secured contractually, though some uncertainties remain in the case of Denmark, Portugal, the United Kingdom and possibly also Italy, where national energy planning now envisages an even more significant role for gas than previously expected. Although few Member States will be dependent upon a single non-EC source of gas, the number of major gas suppliers is generally small. Only Gaz de France already has purchase contacts with all three major non-Community suppliers while six other Member States have existing arrangements with two of them.

2.9 It would, for the foreseeable future, be unrealistic to expect a further major increase in the geographical diversification of gas supply sources for the Community. The European Commission's short and medium term approach to the question of supply security is to stress the importance for the gas industry and its consumers of measures which would allow them to handle a major supply interruption. Historically, it should be noted, the reliability of non-Community supplies has generally been quite high. Perhaps the most serious interruptions to supply occurred with relatively small scale imports from Libya and more significant under-deliveries of Algerian LNG to France in 1980-81, when there was a major dispute over pricing. Norwegian deliveries have on occasions been adversely affected by short-term strikes offshore and by recent production difficulties at the Ekofisk field. There were some winter under-deliveries of Soviet gas to Western Europe in the mid 1980s due to unexpectedly high offtakes in Eastern Europe but these problems now appear to have been resolved. Of the three major producers supplying Member States from outside the Community, Norway is the only OECD country and therefore politically regarded as the most reliable for the future. In terms of past supply performance, however, the USSR has proved at least as reliable. At least in the absence of very major east-west tension, it could be argued that the USSR has every economic incentive to maintain this reputation for reliability.

2.10 Notwithstanding the fairly good historical experience with non-EC suppliers, the Algerian difficulties and past experience of supply interruptions in the oil market underline the wisdom of measures to provide for a major disruption to supplies. Such measures essentially involve three principal elements:

(a) the availability of underground gas storage within the Community;

(b) interruptible sales contracts with large industrial or power station users who have alternative fuels, which allow supplies to be cut off in periods of peak demand or supply shortage; and

(c) the flexibility to reroute gas flows within the interconnected European transmission grid to cope with failure of one supply source by redirecting additional gas from other sources.

In the case of both storage and interruptible sales, it is important to recognise that these can play a key role in seasonal supply/demand matching as well as serving strategic supply security objectives.

2.11 The extent of gas storage facilities varies considerably across Member States, depending on the availability of partially-depleted onshore gas fields, salt strata suitable for salt cavity storage, naturally occurring aquifers or other potential gas storage facilities such as worked-out mines. Exceptionally, British Gas has developed an offshore storage facility, its own seasonally producing offshore gas field and a gas purchase contract for very low load factor supplies; these expensive measures reflect the paucity of suitable onshore storage possibilities. Drawing on utility annual reports and other sources, the current availability of seasonal gas storage in the the various Member States is estimated to be broadly as follows:-

Table 2.4: Availability of seasonal gas storage in Member States, 1986-87
(working storage volume as % of annual sales)

B	D	DK	Esp	F	I	Irl	L	NL	UK	EUR-12
(87)	(87)	(87)	(87)	(86)	(86)	(87)	(87)	(87)	(87)	(est)
6%	10%	11%	-	20%	27%	-	-	-	6%	6%

Thus France and Italy, each of which has a relatively high degree of dependence on non-Community supplies, have both developed a very large amount of underground storage which allows them to manage seasonal demand fluctuations and enhance their strategic supply security as well. At the other extreme, the very considerable flexibility afforded by the Groningen field has meant that the Dutch are only now beginning to plan the installation of other storage facilities. Belgium has also benefited from the flexibility provided by Dutch supplies - which still account for nearly half the nation's gas supplies - while the extent of indigenous gas production in countries like Denmark, Ireland and the United Kingdom means a much reduced strategic need for storage. In the UK, the figure for storage alone is perhaps a little misleading because of the substantial peak production capacity of the seasonal gas fields Morecambe and Sean.

2.12 Interruptible gas sales in some Member States - such as the United Kingdom, West Germany and Belgium - are used primarily as an instrument of seasonal supply/demand match in severe winters to release gas supplies and pipeline capacity for those consumers who cannot be interrupted. In other cases, such as France and Italy, interruptible customers are rarely interrupted in normal circumstances as their extensive gas storage is used for seasonal supply/demand match. Thus the capacity to interrupt remains a strategic reserve to be used in the event of severe disruptions to gas supply. In the Netherlands, the seasonal flexibility of Groningen output is such that there are no interruptible contacts, other than with power stations and very large feedstock users, and there has rarely been any actual interruption by Gasunie. The extent to which gas is actually sold on an interruptible basis also varies as between Member States, as indicated by our estimates in table 2.5 below.

Table 2.5: Interruptible sales as a proportion of the total, 1986-87

B	D	DK	Esp	F	I	Irl	L	NL	UK	EUR-12
(87)	(87)	(87)	(87)	(86)	(86)	(86)	(87)	(87)	(87)	(est)
21%	15%	48%	44%	18%	29%	45%	n/a	19%	21%	21%

Note: Some uncertainty surrounds these figures, particularly in West Germany where no published information is available. For other countries, a firm/interruptible split is frequently available for industrial sales but no breakdown is given for chemical feedstock or power station sales. In the absence of specific knowledge (eg. mainly interruptible feedstock sales in the UK), we have assumed that feedstock sales are firm and power station sales interruptible.

2.13 The third main factor which contributes to natural gas supply security is the flexibility of operation of the interconnected gas grid itself. Although the European Commission recognises that the development and integrated operation of the pipeline network will essentially reflect the commercial objectives of the companies concerned, it nevertheless monitors the situation carefully and seeks to encourage further integration. To this end, the members of COMETEC-GAZ (the association of major European gas companies) produced a comprehensive July 1986 study for the attention of the Commission entitled "The contribution of the European network to security of supply". In turn, the conclusions of the study were reflected in the communication COM(86) 518 already referred to from the Commission to the European Council. The communication points out that integrated operation is facilitated by joint venture ownership of key transmission pipelines such as TENP (SNAM/Ruhrgas), MEGAL (Ruhrgas/GdF/OMV) or SEGEO (GdF/Distrigaz). There are often significant differences in gas quality (principally CV and Wobbe) between Groningen gas, Soviet exports, North Sea gas from various sources and Algerian LNG. Thus separate L-gas and H-gas grids are operated in Belgium, the Netherlands, the north of West Germany and northern France to accommodate low CV (Groningen quality) and higher CV gas respectively. However, the use of gas mixing stations and processing plant allows some degree of interchangeability of gas from the various different supply sources when additional flexibility is required.

2.14 In normal circumstances, integrated operation of the interconnected grid allows the major continental gas utilities to reduce transmission costs through various "gas swap" arrangements. For example, it is unlikely that all the Norwegian gas recently contracted for sale to OMV from 1993 will physically be delivered to Austria; instead, some Soviet gas contractually destined for West Germany might well be delivered to Austrian consumers while West Germany receives some of the Norwegian gas purchased by OMV. Similarly, north German gas companies BEB and Thyssengas do not normally take delivery of Soviet gas purchased under the USSR IV contract. This gas is usually delivered to Ruhrgas customers in south Germany, while BEB and Thyssengas receive North Sea or mixed North Sea and Groningen gas instead, out of the volumes contractually deliverable to Ruhrgas. Nevertheless, the transmission companies provide the additional pipeline capacity to ensure that all gas could be physically delivered to the purchaser in exceptional circumstances. This sort of flexibility is then used to deal with supply interruptions. For example, disruptions in 1981 and 1986 to Norwegian deliveries to Emden (West Germany) were overcome by transporting additional gas (originating in the USSR) from the south to the north of West Germany. Similarly, Distrigaz adjusted to the interruption of Algerian LNG deliveries through France in late 1986/early 1987 (due to labour difficulties in France) by stepping up Dutch and Norwegian imports. In turn, additional LNG offtakes from Algeria were used to compensate for under-deliveries from Norway due to major works at the Ekofisk field in the summer of 1987. In general, there is no technical impediment to the re-routing of gas within an acceptable time period. Thus the normal east-west flow of Soviet gas to France through the MEGAL line could, for example, be reversed to a west-east flow in the event of disruptions to West German supplies from the USSR.

2.15 Taking all the possible measures for dealing with a major supply interruption into account, the European Commission drew the conclusion in COM(86) 518 that "for the period 1986-1990 existing and planned security measures, when applied on a Community-wide basis to those countries on the European continent which are interconnected, should be sufficient to deal effectively with an interruption of supply from any individual import source for at least nine months". It should, however, be recalled that five Member States - Greece, Ireland, Portugal, Spain and the United Kingdom - are not as yet connected to the integrated European grid, though there are proposals in Spain for a link to the French network in the 1990s. In future, the availability of two pipelines from the Norwegian North Sea to continental Europe (Zeepipe to Zeebrugge as well as the Statpipe/Norpipe system for deliveries to Emden) will add to the flexibility of the pipeline system. Similarly, a connection between the UK and mainland Europe could make an important contribution to supply security, especially at times when UK gas fields have considerable excess production capacity outside the peak winter period. Such a link is, however, only likely to be built if there is a sufficient commercial opportunity for UK gas exports to the continent or if gas exported or re-exported from the continent can find a place in the UK supply/demand match.

The internal gas market

2.16 Not only for reasons of increased supply security, but also in order to promote greater competition and efficiency in gas supply, the European Commission has identified as a further objective the need to achieve a more open internal market in natural gas. Specifically, the Council Resolution of September 1986 on new Community energy policy objectives referred to "greater integration, free from barriers to trade, of the internal energy market with a view to improving security of supply, reducing costs and improving economic competitiveness". This theme was subsequently developed in the Commission Working Document COM(88) 238 entitled "The Internal Energy Market", which provided an inventory of existing obstacles to the achievement of the integration objective.

2.17 The Commission's Working Document recognised the fact that natural gas supply within the Community is characterised by a series of national, regional or local monopolies. Although gas competes with other fuels in most of its end-markets - such as HFO for industrial steam-raising and electricity or gas oil for space heating in the household sector - there is for practical purposes no competition between gas suppliers for sales to end-consumers anywhere in the Community. In cases where competition from other fuels is not particularly intense, as with many small-medium industrial or commercial users who could not easily install oil storage tanks, for example, there is arguably a lack of competitive pressure on gas suppliers to operate efficiently and minimise costs. In general terms, therefore, COM(88) 238 concludes that a more open and competitive market could lead to reduced energy costs and a rationalisation of energy industry structures within the Community.

2.18 There is an important link here to the Community's more general objectives for an internal market in goods and services. Considerable emphasis, in the 1985 White Book and elsewhere, is laid on developing conditions in which industrial and other enterprises across the Community can compete on an equitable basis. Particularly in energy-intensive sectors of manufacturing industry such as steel, glass, building materials and basic chemicals, gas and other energy costs comprise a significant proportion of total production costs - exceeding 25% for some basic chemicals (like PVC) and other very energy-intensive products. Some manufacturing processes with high power requirements may in fact give rise to a high demand for gas because of gas-fired power generation on site. Where natural gas is used as a feedstock for ammonia and methanol production, gas alone can account for over 80% of total costs. Distortions away from a competitive level of gas and other energy prices can therefore have a very considerable impact on the pattern of production, competition and trade within the Community in a number of key industrial sectors. A move towards a more open internal gas market could therefore make an important contribution towards the completion of an internal market in the output of these industries as well.

Natural gas pricing

2.19 In April 1983, the European Council issued a Recommendation (O.J.E.C. No L123) on methods of forming natural gas prices and tariffs in the Community. It is perhaps worth recalling that this Recommendation was made at a time when the "comparative scarcity of natural gas" was perceived to be a more significant constraint than it might be today. Nevertheless, the Council attempted to confront a major difficulty in natural gas pricing which remains an important issue - namely the possible conflict between the competitive market position of natural gas, which may require market-related pricing in line with competing fuel prices, and the perceived need for a rational gas pricing structure which reflects the supply and distribution costs for the various categories of gas supply. The Recommendation effectively concluded that gas prices should reflect market value but at least cover costs; by implication this suggests a cost-related floor to market-related prices, below which gas utilities should not seek to sell. Specifically, "natural gas prices should be as close as possible to the market value of natural gas in relation to the price of substitute forms of energy and guarantee sufficient proceeds to cover the cost of supply to consumers".

2.20 The Recommendation appears to have considered both tariff and non-tariff (contract) sales to large gas consumers, though in the latter case its guidance is extremely general, referring only to prices "calculated in the light of cost and market conditions". However, it is unlikely that the European Council envisaged that market conditions should be assessed on an individual consumer basis, since the Recommendation also called for "the greatest possible degree of transparency" and recommended that "these prices and the cost to the consumer are made public as far as possible". The arguments for transparency are essentially twofold:

(a) that consumers should have a clear basis for making rational decisions on fuel choice and industrial location, for example; and
(b) particularly in the light of the objectives relating to the internal gas market, that potential competitors should face a clear "yardstick" against which to gauge their market entry strategy.

2.21 In a significant number of instances - particularly in West Germany and the United Kingdom - natural gas pricing to large users is not at all transparent and could potentially constitute a constraint on the development of a more open and competitive internal gas market. An important question is the extent to which such pricing patterns represent a legitimate response to competition from other fuels (especially oil products), rather than anti-competitive gas pricing of a discriminatory kind, and these issues will be discussed at greater length in Section III below.

Issues for common carriage

2.22 A number of important implications for a possible common carriage system emerge from our discussion of the Community's energy objectives, including:

(a) any impact of common carriage on the competitive position of Community gas producers and the further development of indigenous gas reserves;
(b) its impact on the bargaining position as between non-Community gas suppliers (Algeria, Norway, USSR etc) and gas purchasers within the Community;
(c) any effects on long term gas supply security, via the incentives to develop and extend gas transmission, storage and distribution systems within the Community and to operate them in a more integrated manner;
(d) any effects on long term gas supply security via the incentives to develop new sources of gas supply, both within and outside the Community;
(e) the likely effect of common carriage in terms of increased competition, reduced gas supply costs and rationalisation in the gas supply sector; and

(f) its impact on gas pricing systems, especially for larger gas consumers.

Each of these implications will be discussed at greater length when the possible advantages and drawbacks of common carriage are considered in Section VI.

III THE GAS SUPPLY SITUATION IN THE COMMUNITY

3.1 A realistic assessment of the possible advantages and drawbacks of a gas common carriage systems at the Community level requires a focused analysis of the gas supply situation in Member States as it currently exists or may develop in the future. Of particular relevance to the present study are those features of the gas supply situation which:

(a) currently constitute a barrier to free internal trade in natural gas;
(b) would play a role in determining the conditions under which a common carrier system could be effective; or
(c) would influence the way in which an effective common carrier system would impact on consumers, the gas industry or the Community as a whole.

3.2 The key features of the Community's gas supply position when seen from this perspective include:

(a) the organisational structure of the gas industry, degree of vertical integration and commonality of ownership as between transmission and distribution companies;
(b) the ownership of the gas transmission grid and the extent to which it is already utilised by contracted gas supplies;
(c) the cost structure of the organisations involved in gas production, supply and distribution;
(d) pricing policies for gas sales, particularly to larger consumers and distribution companies who might be able to take advantage of common carriage;
(e) developments in the market for gas, especially the possible generation of electricity from gas in efficient, combined cycle plant;
(f) developments on the supply side of the industry, the extent of any unsold production potential in producing countries and the degree to which supplies are already contracted to meet projected future gas demand; and
(g) the important differences that exist between the current gas supply situation in the Community and the circumstances which have given

rise to widespread use of third party gas transportation in the United States.

In this section of the report, we discuss each of these key features in turn and then draw out the main implications for gas common carriage.

Gas industry organisation

3.3 The way in which the gas industry is structured and organised varies quite widely across Member States, although certain common features emerge in a number of cases. For reference, the situation in each Member State is presented in a highly summarised form in table 3.1 overleaf, which distinguishes between gas production, transmission and distribution activities. Typically, gas production (where it takes place) tends to be organisationally separate from transmission and distribution. Frequently, exploration and production activities involve a wider range of international oil and gas company interests than do the "downstream" operations of the gas industry. Gas production in most Member States is not, therefore, a state monopoly or near-monopoly activity. Nevertheless, there is very considerable state involvement in the upstream gas industry in major gas-consuming countries such as France and Italy, for example. In the Netherlands, the state is involved in the financial rather than operational aspects of NAM's gas production business - effectively extracting economic rents when gas prices are high in relation to production costs and taking a high proportion of the income reduction when selling prices are relatively low. It is also worth noting that, among the international oil companies, Shell and Esso are important gas producers in number of Member States including the Netherlands, West Germany and the United Kingdom.

3.4 Bulk gas importing and transmission, in contrast to production, is an activity carried out by a single national organisation in the vast majority of Community Member States. In a good many cases, that organisation is also 100% owned by the state (in Denmark, Italy, Spain and the Republic of Ireland, for example) while in other cases (Belgium and the Netherlands) there is mixed ownership with considerable state involvement and control. Although GdF does not have a complete geographical monopoly of gas

Table 3.1: Organisational Structure and Ownership of [illegible] Natural [illegible] EC Member States

	B	D	DK	Esp	F	He	I	Irl	L	Nl	P	UK
Total 1987 gas consumption (mtoe)	7.5	44.8	1.4	2.8	25.3	0.1	33.0	1.3	0.3	33.6	-	48.9
Industry Structure	Separate T&D	Complex, with two transmission tiers	Separate T&D	Separate T&D	Vertically integrated (T&D)	-	Separate T&D but strong ENI involvement througout	Virtually integrated	Separate T&D	Separate T&D	-	Vertically integrated (T&D)
PRODUCTION	-	BEB (owned by Shell/ Esso), Mobil, Wintershall & others	DUC (A.P. Moller, Shell & Texaco)	Hispanoil (an INH subsidiary)	Almost all SNEA(P) (majority owned by the state)	Not significant	Dominated by AGIP (part of 100% state owned ENI group)	International oil companies - currently Marathon (Kinsale head)	-	Mainly NAM (Shell/ Esso with state financial involvement), plus others	-	International oil and gas companies plus British Gas subsidiaries (less than 10%)
TRANSMISSION	Distrigaz: 50% state (direct & indirect) 17% Shell 33% Intercom & Tractabel	Ruhrgas, BEB & Thyssengas plus 13 regional transmission companies	DANGAS - subsidiary of 100% state-owned DONG	ENAGAS (100% state owned), a subsidiary of state holding company INH	Mainly GdF (100% state) Also SNGSO (Elf/GdF) in SW and CeFeM (GdF/ Elf/Total) in central France	It is proposed to establish a vertically integrated National Gas Company which would be a subsidiary of state owned oil company DEP	SNAM (also a 100% ENI subsidiary) plus a small, independent grid in central Italy	BGE (100% state)	SOTEG: 50% state 50% steel industry	Nederlandse Gasunie: 25% Shell 25% Esso 10% State 40% DSM (state)	-	British Gas plc - previously 100% state owned but now 100% private, with no significant large corporate shareholders
DISTRIBUTION	4 public & 19 mixed enterprise local distributors. Private co Intercom & municipalities are both heavily involved	Over 500 distributors, of which 85% are wholly in public (municipal) ownership	5 municipally owned regional distributors plus the Copenhagen gas utility	Local distribution companies	Almost entirely GdF. Some 2.5% of sales are accounted for by municipal/ independent distn.cos.	-	1700 distributors: local authorites, municipal cos, mixed and private enterprise	Town gas companies now mainly absorbed into BGE	3 local/ regional companies with a fourth company under formation	Many municipal distributors, currently being reorganised to reduce their number	-	BG, as above
Other remarks	The gas industry is supervised by a Control Committee (Govt, TU & industry representation)	Elect. companies RWE, VEW & EWE also import gas from the Netherlands	Other consortia exploring for gas but DUC is still the only producer	-	GdF/EdF operate joint distribution/ billing activities	-	SNAM subsidiaries (esp Italgas) account for 25-30% of distribution	-	-	-	Consideration is being given to establishing a gas industry based on LNG imports	Limited gas sales from BP to its own petrochemical plant

transmission in France, it actually operates the CeFeM network in the centre of the country and does not in any way compete with SNGSO, which is responsible for supplying Lacq area gas in the south west of France. British Gas now provides an interesting exception to the general pattern, in that (pending the emergence of competitors) it is a privately owned monopoly seller and is likely to remain the dominant bulk transporter of natural gas in the United Kingdom. Only in West Germany are there several major importing transmission companies, but in practice they tend to co-operate rather than compete for bulk purchases and Ruhrgas is very much dominant in terms of size and importance, as over 70% of gas sold in West Germany passes through its hands.

3.5 Only in France and the United Kingdom are gas transmission and distribution activities vertically integrated within a single company, though the Republic of Ireland is also moving in this direction as BGE absorbs financial-troubled city distribution companies. In other cases, a single national transmission company is complemented by a number of regional or local gas distribution companies, many of which are municipally owned. The West German situation is somewhat exceptional, in that there is a third industry tier of regional transmission companies between the main importing utilities (Ruhrgas, Thyssengas and BEB) and the distributors. Belgium is also interesting in that there is an unusually high proportion of private ownership in the distribution sector, where Intercom is a particularly important player. Where transmission and distribution activities are separate, the usual arrangement is for the national transmission company to sell gas direct to larger consumers as well as to the distributors, who then on-sell to households and other smaller gas users.

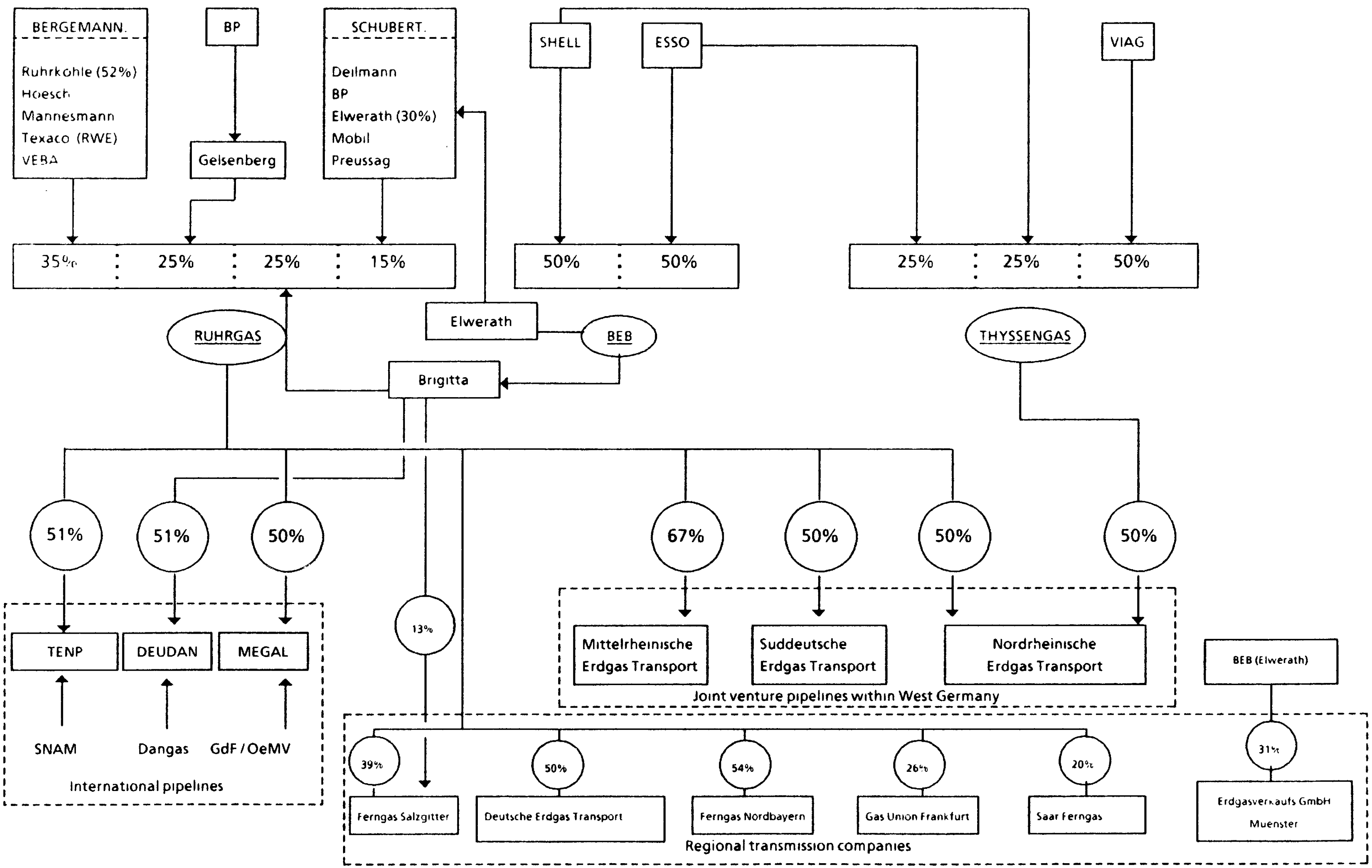
3.6 As mentioned above, the structure of the West German gas industry is particularly complex and may merit some separate discussion, given the size of the West German market and its central importance to the integrated gas grid in Western Europe. The ownership pattern is a complicated web of cross-holdings and sub-holdings which involves a number of major West German industrial and mining concerns as well as some of the major international oil companies or their West German subsidiaries. The ownership of the three principal gas importing transmission companies

(Ruhrgas, BEB and Thyssengas) is set out for reference in figure 3A overleaf. This also shows and the widespread interests which Ruhrgas holds in major international trunklines, joint venture transmission lines within West Germany and a number of regional transmission companies. Although there is some indirect public sector interest in both Ruhrgas and Thyssengas, the degree of private ownership in the main West German gas transmission companies is significantly higher than in most other Member States. In comparison to the more diversified mix of gas supplies obtained by Ruhrgas, Thyssengas and BEB are much more dependent on supplies from the Netherlands (still over 60% of Thyssengas' supplies) and indigenous gas supplies (nearly two-thirds of BEB's gas supplies) respectively. Thyssengas has a relatively small supply area in the western part of the country while BEB, which supplies a part of northern Germany, also sells a significant portion of its supplies on to Ruhrgas and other transmission companies. In addition, BEB is by some margin the leading gas producer in West Germany. A very substantial proportion of Ruhrgas' gas supplies is sold on to regional transmission companies, although sales are also made to distributors and larger final consumers. In 1987, for example, over 60% of the company's sales were made to other pipelines, almost 25% to local utilities and only 15% direct to industrial users. As a whole, importing and regional transmission companies between them provide about half of all gas sold to end consumers. The five regional transmission companies shown in figure 3A in which Ruhrgas has a stake alone account for over 25% of total gas use in West Germany. Apart from the Ruhrgas holdings, significant interests in these companies are also held by local municipalities and sometimes by steel or mining companies. In addition, there are other regional transmission companies which are entirely owned by provincial (Laender) and municipal governments. An important example is Bayerische Ferngas (Bayerngas), one of the largest regional transmission countries, which supplies over 4 bcm/a of gas to the southern part of Bavaria. It is also involved, with Ruhrgas, in supplying gas to the local utility in the Austrian Tyrol.

3.7 The commonality of ownership as between some (regional) transmission companies and local distributors observed in West Germany is also a feature of several other Member States' gas industries. This is true of Italy, where SNAM subsidiaries owned wholly or in part through Italgas are

Ownership of West German gas transmission companies

Figure 3A



involved in gas distribution in a number of major cities and account for some 25-30% of all gas distributed in Italy. In Belgium, Intercom are a major energy distributor and also hold a significant minority stake in Distrigaz. This commonality of ownership may or may not have an impact on the commercial relationships between the parties concerned, depending on the nature of the sub-holding and the other ownership stakes involved.

The gas transmission network

3.8 The integrated European gas grid currently covers France, Belgium, Netherlands, Luxembourg, West Germany, Denmark and Italy (i.e. seven out of the twelve EC Member States) together with Austria and Switzerland. The major pipelines which comprise the grid are shown in the map overleaf. In comparison to the complex system of interstate pipelines under diversified ownership in the United States, for example, there are relatively few gas trunklines in Western Europe and their ownership is concentrated in the hands of a small number of major gas utilities and (to a lesser extent) international oil companies. Details of the main joint venture transmission pipelines are set out in table 3.2 overleaf, which also illustrates the key role which is played by Ruhrgas in this respect. Located at the centre of the integrated gas grid, they are responsible for operating several key pipelines including TENP, the major north-south link across central Europe and MEGAL, the major link in an east-west direction. As discussed in Section II above, these arrangements facilitate flexible system operation in the event of disruptions to supply or gas transportation. However, they also put the major transmission companies in a very strong bargaining position vis-a-vis their customers and other gas utilities. This was illustrated, for example, by Ruhrgas opposition to proposals made by Bayerngas for direct purchases of Algerian gas, a dispute which was eventually resolved by the offer of more favourable terms for Ruhrgas' sales to Bayerngas. Similarly, Ruhrgas expressed strong views on Norwegian plans to transport gas across West Germany to Austrian utility OeMV on a tariffed basis, preferring instead a purchase and resale arrangement. Ruhrgas' concerns in this case appear to have included the possible implications of a common carriage precedent if Norwegian plans had been allowed to reach fruition, especially as the sellers proposed to retain title to the gas through West Germany to the Austrian border.

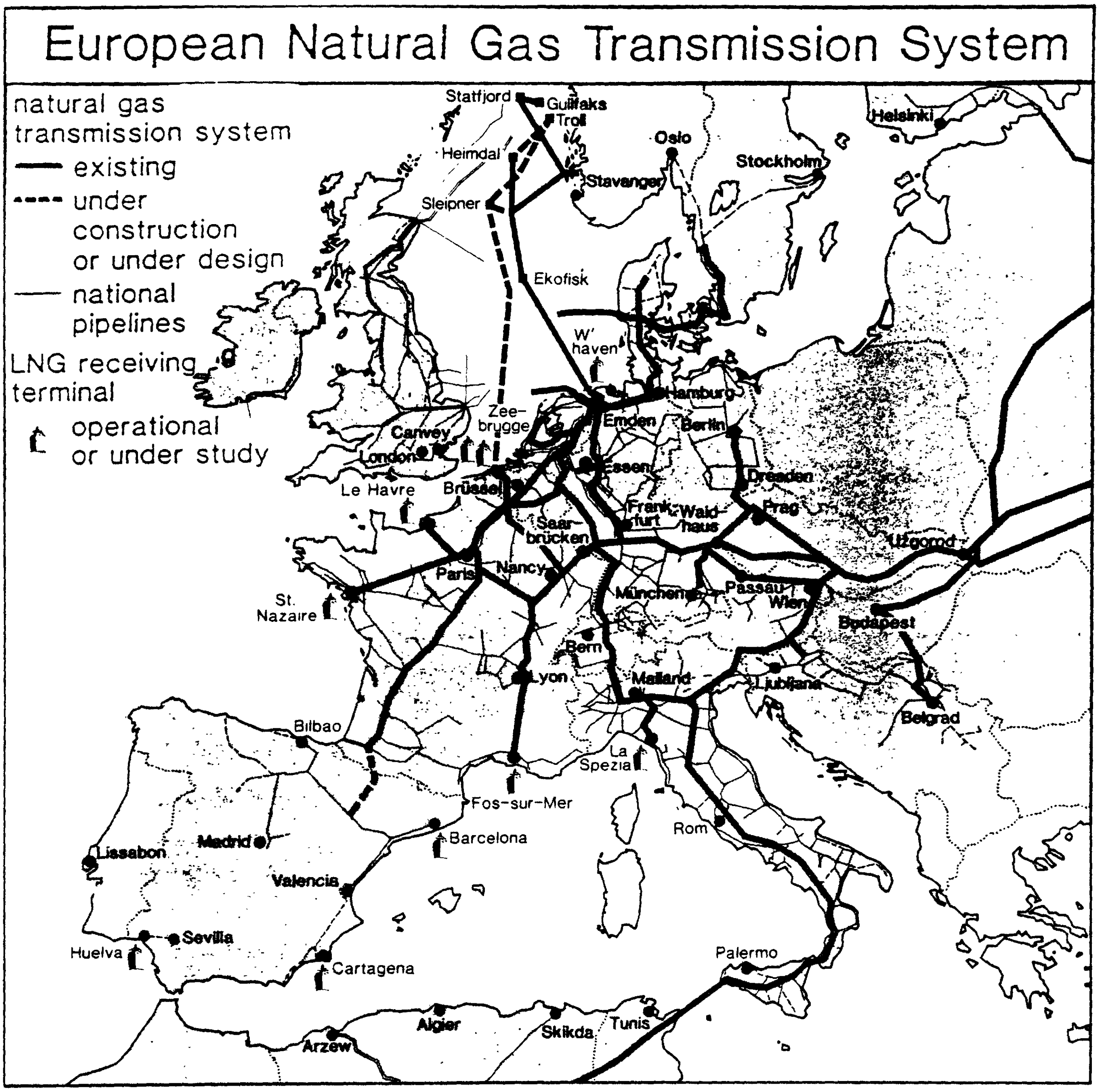

European Natural Gas Transmission System
natural gas transmission system
existing
under construction or under design
national pipelines
LNG receiving terminal
operational or under study
Statfjord
Gullfaks
Troll
Heimdal
Oslo
Stockholm
Helsinki
Stavanger
Sleipner
Ekofisk
W' haven
Hamburg
Emden
Berlin
Zee-brugge
Canvey
London
Essen
Dresden
Le Havre
Brüssel
Frank-furt
Wald-haus
Prag
Saar-brücken
Uzgorod
Paris
Nancy
München
Passau
Wien
St. Nazaire
Budapest
Bern
Lyon
Mailand
Ljubljana
Belgrad
Bilbao
La Spezia
Fos-sur-Mer
Barcelona
Rom
Madrid
Lissabon
Valencia
Sevilla
Huelva
Cartagena
Palermo
Algier
Skikda
Tunis
Arzew

Table 3.2 : Major joint-venture gas trunklines in Western Europe

Name of pipeline		Shareholders (% interest)	Length	Principal role
NETG	Nordrheinische Erdgas-transport GmbH	Ruhrgas AG(50) Thyssengas GmbH(50)	644km	Transmission within West Germany, principally of Dutch 'L' gas exports
METG	Mittelrheinische Erdgas-transport GmbH	Ruhrgas AG(66) Exxon (17) Shell Petroleum(17)		
SETG	Suddeutsche Erdgas Transport GmbH	Ruhrgas AG(50) Exxon(25) Shell Petroleum(24) Nederlandse Maatschappij(1)		
SEGEO	Societe Europeenne de Gazoduc Est-Ouest	Distrigaz (Belgium)(75) Gaz de France(25)		Norwegian gas to Belgium and France
DEUDAN	Deutsch/Danische Erdgas-transport-Gesellschaft mbH	Deudan-Holding GmbH(51) =Ruhrgas/BEB Dangas GmbH(49)		Danish gas through West Germany to BEB and Ruhrgas
TENP	Trans Europa Naturgas Pipeline GmbH	Ruhrgas AG(51) SNAM(49)	500km	Dutch 'H' gas from Netherlands border to West Germany/Switzerland/Italy
TAG	Trans-Austrian Gasline	SNAM (Italy) OMV (Austria)	383km	Soviet gas from Czech/Austrian border to Austrian/Italian border
TMPC	Transmediterranean Pipeline Company	SNAM(50) Sonatrach (Algeria) (50)	2500km*	Algerian gas to Italy
MEGAL	Mittel-Europaische-Gasleitungsgesellschaft	Ruhrgas AG(50) Gaz de France(43) OMV AG (Austria)(5) Stichting Megal Verwaltungsstiftung Heerlen/Nl.(2)	629km	Soviet gas from Czech/West German border to south of Germany and France
WAG	West Austrian Gasline	Ruhrgas AG OMV AG Gaz de France	245km	Soviet gas from Czech/Austrian border to MEGAL (Austrian/W.German border)

* Hassi R'Mel (Algeria) to Minerbio in the Po Valley (Northern Italy). Some 370km in Tunisia are jointly owned by the Government and SNAM, 155km are underwater to cross the Mediterranean and 15km cross the Strait of Messina.

3.9 Again in contrast to the situation in the United States, the utilisation of the main transmission lines in Western Europe is generally fairly high. This reflects the continued growth of total gas demand in many Member States and the increasing market share of non-Community supplies, which has necessitated the expansion of long-distance pipeline capacity. Thus the general tendency is in fact for pipeline capacities to be increased over time (by "looping" of lines or additional compression, for example) in order to meet growing transmission requirements. Increases in MEGAL, Mittelrheinische Erdgastransport and Nordrheinesche Erdgastransport pipeline capacities are reported by Ruhrgas to have taken place in 1987, while the Trans-Austria Gasline (TAG) has recently been looped in order to provide the 18 bcm/a of capacity required to carry additional Soviet gas to Italy and Yugoslavia. TENP capacity has also been progressively expanded over the years, primarily to cater for increased demand for gas transported by Ruhrgas and then sold to other transmission companies such as Thyssengas, Gas Versorgung Suddeutschland and Swissgas. SNAM has not expanded its share of TENP, however, and the volumes of gas it imports into Italy from the Netherlands have tended to decline somewhat in recent years. Nevertheless, SNAM now appears to be taking Dutch gas on a somewhat lower load factor than in previous years, so that it continues to use its subscribed capacity fairly fully at times of peak demand.

3.10 In general, therefore, we have formed the view that the integrated pipeline grid is quite highly utilised. There are, however, a number of provisos to be made to this conclusion:

(a) where gas demand is projected to increase rapidly, there will inevitably be some short term spare capacity, since it is most economical to build lines large enough to cater for the levels of use expected some years into the future. This is currently the case in Denmark, Ireland and parts of the Italian pipeline system, for example;

(b) in certain instances where gas demand has failed to achieve the projected level, there may be spare capacity or potential spare capacity in the system. This may be the case in parts of Belgium, for example;

(c) gas swap arrangements may leave parts of the system underutilised. However, this is not truly "free" capacity since it would be neded to preserve supply security in the event of disruptions to supply;

(d) the commissioning of Zeepipe in the mid 1990s may ease pressure on transmission capacity in north Germany and the Netherlands;

(e) pipeline capacity can often be increased through looping lines or adding compressor stations; and

(f) a distinction must be made between year-round spare capacity and spare capacity outside periods of peak demand.

3.11 It may perhaps be helpful to enlarge somewhat on the last of these points. Since overall gas demand is considerably higher in summer than in winter, it might be argued that the available pipeline capacity is under-utilised outside the period of peak demand and that direct supplies/common carriage which are interruptible in the winter months at the pipeline owner's option could help make better use of both production and transportation facilities. An interruptible gas supply of this sort could perhaps be accommodated by large industrial users with dual-firing facilities and the carriage charge ought to be low since no additional capacity costs are imposed on the system by such an arrangement. In practice, the situation is somewhat more complex than this. The main producers of "H" (high calorific value) gas supplied into Western Europe are Norway and the USSR and they have had to build high cost facilities - offshore platforms and pipelines in the case of Norway, very long distance onshore transmission lines in the case of Soviet exports to the west. They therefore supply on high load factor in order to utilise them at a high level throughout the year and thus keep down unit fixed costs. These supplies are used by purchasing gas transmission companies to meet year-round gas demands and to fill up seasonal storage and there is thus little or no spare summer capacity in the major pipelines such as MEGAL or SEGEO which are used to carry such high load factor "H" gas supplies. LNG supplies from Algeria are generally also high load factor in principle, although in practice somewhat more flexibility may be available in the scheduling of shipments. This leaves lower load factor supplies from the Netherlands (mainly "L" gas of lower calorific value) or from certain indigenous sources such as West German sweet gas production. In such cases there will be spare pipeline capacity outside the winter peak, but indigenous gas producers outside the UK generally have little additional gas to offer for direct sale and the Dutch have a policy of conserving Groningen gas which makes them unlikely to want to offer additional summer volumes, even if there were a market for such gas via common carriage.

3.12 Before leaving the subject of the gas transmission system within the Community, it is worth noting the extent to which gas already circulates within the integrated grid through arrangements between pipeline owners. We have already referred to a number of joint venture pipelines, which carry gas on behalf of the partners in the joint venture. There is sometimes a small initial capital contribution, but much of the capital cost is normally raised on international capital markets. Each partner in the venture subscribes to a given proportion of the total capacity of the line and then pays a tariff (often divided into capacity and commodity charges) to the joint venture company for the use of the line. Where there is greater flexibility to use a number of different pipelines, gas is often transported on a tariffed rather than a joint venture basis. Examples of gas transportation on this basis include:

(a) Dutch gas transported through Belgium by Distrigaz for Gaz de France;
(b) Norwegian gas transported across France by GdF for Elf/CeFeM;
(c) the recently agreed deal whereby GdF will transport Norwegian gas across France on behalf of the sellers for sale to Enagas at the Spanish border;
(d) arrangements between Thyssengas and other transmission companies such as Ruhrgas and VEW in West Germany; and
(e) transportation of gas by SNAM for independent indigenous producers, such as Montedison, from their own fields to their chemical plants on the SNAM grid.

Such arrangements typically involve a "ship-or-pay" (use-or-pay) commitment from the shipper as well as a tariff payment to the pipeline owner. It is important to emphasise that these arrangements are almost all made on a long term basis between gas utilities and there is no short term "spot" market in gas transportation or pipeline capacity.

The structure of gas supply costs

3.13 An important element in the assessment of a possible gas common carriage system is the extent to which a more open, competitive environment might stimulate greater efficiency in gas utilities and thus lower unit gas supply costs to consumers. In order to gain a realistic understanding of the potential for such cost reductions, it is important to take into full account the current and likely future structure of gas supply costs in Western Europe. The cost of gas supply typically consists of four main cost components:

(a) the cost of bulk gas purchase;
(b) the cost of transmitting gas from the point of supply to the offtake point for the local distribution grid;
(c) storage and other seasonal supply/demand matching costs (eg peak-shaving plant); and
(d) the cost of distributing gas from the offtake from the transmission grid to the consumer.

For large industrial customers located on the transmission grid, however, there is no distribution cost and the main cost elements are thus bulk gas purchase and transmission.

3.14 The cost of gas purchase accounts typically for a very high percentage of total supply costs. Pricing clauses in bulk purchase contracts typically comprise a base price and an indexation mechanism for adjusting that price over time. Many contracts also envisage a periodic review of the base price itself in the light of changing market conditions. The base price at which gas is purchased at the supply point from producer to buyer generally reflects the price of alternative fuels at the burner tip, less the non-gas costs of supply from the bulk supply point to the consumer. This is called the "netback" pricing principle and the producer of the gas will normally seek to receive the maximum price at which gas will continue to be competitive with alternative fuels in the market. It is in the interest of both the producer and the transmission company that gas stays competitive with other fuels over time and the price at which gas is sold is therefore typically linked to an index of a basket of alternative fuels. In the most cases, the link is largely to changes in oil prices, but there are variations in some instances depending on the market situation into which the gas is sold. For example, British Gas now seeks to link purchase prices in new contracts to oil when oil prices are low, while moving to a "mixed basket" (inflation, electricity prices, oil) to protect its competitive position against coal and (especially) electricity when oil prices are high. For similar reasons, some of the continental buyers (such as Gaz de France) secured the introduction of a partial link to general inflation in the Troll contract when oil prices are high. For gas sales to power stations, coal is often the most direct alternative fuel and the gas price indexation in recent deals such as Miller-Peterhead in the UK and Norway-SEP in the Netherlands reflect this with a coal price or coal proxy (inflation rate) link.

3.15 The purchase prices which the different transmission companies pay for gas tend to lie mainly within a fairly narrow price range, since in most cases the gas price is based on similar market realisations in competition with alternative fuels. There are, however, some differences in price which may reflect perceived security of supply (eg Netherlands or Norway, as compared to the USSR) or else perhaps the non-price terms of the contract concerned. In general, the more flexibility there is in the sales contract, the higher the price the supplier is likely to be seeking. The flexibility can relate to the total annual quantity or else to seasonal offtake variations (load factor of supply). If the contract provides a lot of annual flexibility (i.e. the range between the minimum and maximum amount supplied as outlined in the contract is large), then the transmission company is better able to match contracted suppliers to total demand, without incurring take-or-pay penalties. This is obviously beneficial to the transmission company, which might therefore be willing to pay a premium in order to obtain this flexibility in the contract. If the gas contract is flexible with regard to the load factor of supply (i.e. the transmission company can take more gas in winter than in summer, within the agreed range of total annual quantities), then the buyer might be willing to pay a premium, reflecting a consequent reduction in his own storage costs. Seasonal flexibility is typically provided by fields (such as Groningen) with low unit capacity costs. Some low load factor gas supplies are explicity priced on a commodity charge/capacity charge basis, as in the case of Dutch gas exports and supplies of indigenous West German gas. The Dutch capacity charge is currently understood to be DM80/m^3/hour of capacity required - equivalent to around Pf 1.8/m^3 (ECU 0.01/m^3) at 50% annual load factor, for example. In the United Kingdom, on the other hand, there is no explicit capacity charge except for very low load factor "winter only" fields.

3.16 Basic transmission costs can be divided into a fixed and a variable cost component. The fixed (or capacity) cost component consists mainly of the capital costs of building the transmission pipeline and the subsequent fixed maintenance cost. Both will go up with the length of the pipeline, but there are economies of scale for larger diameter pipes which reduce unit transmission costs, provided that high capacity utilisation can be maintained. The higher the utilisation of the pipeline, the lower the capital cost per unit of gas. The variable costs of transmission are substantially lower than the fixed cost component. The main variable costs are incurred when running compressors to maintain high pipeline pressures and ensure a higher level of gas throughput. Increased compression will lead to higher gas losses and consequently higher transmission costs.

3.17 There is to some extent a trade-off between fixed and variable transmission costs. For example, a transmission company can either build a large sized pipeline which will have sufficient capacity to transmit all the gas needed for the foreseeable future, or it can decide to build a smaller pipeline and to meet increases in demand through the use of additional compressors. The first alternative will lead to an increase in fixed costs, the second to an increase in variable costs, with the trade-off depending largely on the price of gas.

3.18 From the foregoing, it will be apparent that there is no such thing as the cost of gas transmission, since the costs depend on many factors such as pipeline diameter, load factor of supply and distance. To give some idea of the magnitudes involved, however, we may note that British Gas have quoted carriage charges of 3.5 - 4.0 p/therm (around ECU 0.02/m^3) for transportation at 60-90% load factor over distances of rather less than 200 km. These charges reflect transmission through regional (medium-pressure) as well as national (high-pressure) pipelines and the charge for purely high-pressure transmission could well be significantly lower. The non-gas costs of Gasunie in the Netherlands primarily reflect the costs of high-pressure transmission and these are a little less than ECU 0.005/m^3. This low figure may reflect the small size of the Netherlands, as well as depreciation at historic pipeline costs, rather than at rates required to cover the replacement cost of the assets. There has been a tendency, with the fall in gas prices since 1986, for transmission costs to become relatively more important than before. The Gasunie costs are still only 5% of selling prices to medium sized industrial users, while the proposed British Gas charges might be 10-15% of selling prices to a large firm gas customer. Neither the British Gas nor the Gasunie figures, however, include any significant cost element for supply/demand matching by the transmission company. They therefore relate to "pure" transmission costs and considerably underestimate the total non-gas costs of most gas transmission companies.

3.19 A further important element in most transmission companies' total costs is the cost of continuously matching gas supply to the fluctuating level of gas demand. These can be described as the <u>costs of supply/demand match</u>. Seasonal storage and other facilities for matching supply and demand (such as peak-shaving LPG/air plant) are often required, since demand in winter is generally much higher than that in summer, while gas producers are seldom able to provide gas supplies on a sufficiently low load factor to match the pattern of gas demand. The annual load factor of total gas consumption is often around 50% (peak daily demand about double the average daily demand over the year) while some gas producers - such as Norway and the Soviet Union - offer very little seasonal flexibility at all. The cost of seasonal storage will depend on the availability of natural acquifers, suitable rock strata for salt caverns, or partially depleted gas fields. In the case of British Gas, offshore storage has had to be built (the Rough field) and this is particularly expensive capacity. As compared to seasonal storage, which is typically high fixed, low variable cost, some "peak-shaving" plant has relatively low capital costs and high operating costs. This is particularly true of LNG tanks, which have high regasificiation costs and are used to produce gas at high rates for short periods in order to meet the very "needle peak" of winter gas demand.

3.20 <u>Distribution costs</u> consist of the installation and maintenance of the distribution grid, and consumer-specific costs such as gas connections, meter reading, billing etc. There are four main factors which will influence the unit cost of distribution:-

(a) population density;
(b) connection density;
(c) average consumption per gas connection; and
(d) consumer mix.

Population density can actually work both ways, as regards the level of cost. On the one hand, sparsely populated rural areas will always be expensive to provide with gas. However, large densely populated cities can also have relatively high costs because the density of underground pipes and cables makes it expensive to work on the gas distribution grid. A high connection density on the grid will mean that the costs of installation and maintenance of the distribution grid to the population centers will be divided over a large number of (potential) consumers, and therefore the cost per gas unit will usually be low. High consumption per gas connection, for instance because of intensive use of gas for space heating, will mean that the relatively high consumer-specific costs and capital costs will be divided over a high number of gas units and therefore the unit cost will be low. Turning to the distribution companies' consumer mix, overall unit costs will clearly tend to be lower where the distributors are selling to industrial customers as well as smaller residential/commercial users (as in Denmark and, to a lesser extent, in West Germany) than when the local market comprises predominantly small consumers.

3.21 Typical gas distribution margins in a number of different Member States appear to be broadly as follows:

Belgium - about BF 100/GJ on average (ECU 0.08/m^3)
Italy - from around L100/m^3 to L300/m^3 (ECU 0.07 - 0.20/m^3)
Netherlands - less than Gc 10/m^3 (ECU 0.04/m^3) on average
United Kingdom - around 7.5 pence/therm (ECU 0.04/m^3)
West Germany - typically Pf 1.0-1.5/kWh (ECU 0.05 - 0.08/m^3)

Thus the lowest costs tend to arise in those Member States or areas, such as the Netherlands, the UK and the West German Ruhrgebiet, where gas penetration of domestic energy markets and average consumption per consumer are both high. The highest costs are found in parts of Italy where gas has yet to achieve a high market share and consumption of gas for space heating is often lower than in North West Europe.

3.22 In table 3.3 overleaf, we have estimated the average gas costs, non-gas costs and profits per cubic metre for a number of major European gas utilities. As expected, the variance in non-gas costs is significantly higher than that in gas costs. An important reason for this is that some

Table 3.3: Cost Structure of Major European Gas Utilities, 1987

ECU/m^3 (x100)

(% of total in parenthesis)

	Distrigaz	Gasunie*1	Ruhrgas	SNAM	GdF	BG*2
Expenses:						
Gas	9.36 (82)	8.33(95)	6.33(74)	6.63(55)	9.63(55)	9.43(48)
Non-gas	1.73 (15)	0.42(5)	1.63(19)	4.02(36)	7.91(45)	6.73(34)
Profit	0.38 (3)	0.01(0)	0.57(7)	0.60(5)	0.03(0)	3.61(18)
Total	11.47	8.77	8.53	11.25	17.57	19.77

*1 using, in relation to Groningen gas supplies, the "transfer price" for sales from NAM to Gasunie
*2 1987/88, historical cost accounts, gas supply business only

of these utilities are involved in both transmission and distribution. Vertically integrated utilities like GdF and BG have significantly higher non-gas costs than "pure" transmission companies such as Gasunie or Ruhrgas. Gasunie appears to have particularly low non-gas costs because it only incurs transmission costs; the capacity cost of seasonal flexibility is largely reflected in the "transfer price" which it pays to NAM for Groningen supplies. It is significant to note that for all utilities the gas costs are higher than the non-gas costs. This gives some indication of the extent to which increased competition and the possible subsequent improvements in operating efficiency might lead to reductions in overall costs. For the "pure" transmission companies, any reductions in non-gas costs due to greater efficiency would lead to only a marginal reduction in total costs. If, for instance, Gasunie were to achieve a 20% reduction in its non-gas costs, then this would lead to a reduction of only 1% in overall costs. Efficiency improvements by the vertically integrated companies or by local gas distributors might have a somewhat bigger impact on total cost, though gas distribution costs are also dominated by the cost of gas purchases. In 1986, for example, gas costs accounted for an average 76% of total expenses for Belgium gas distributors, which compares to 91% for transmission company Distrigaz in the same year. Taking the two levels in combination, the border price of gas purchased by Distrigaz was 55% of the average price of sales to distributors' customers. There is thus rather more room for efficiency improvements to impact on sales prices to small users, but is doubtful whether the introduction of common carrier would introduce competitive pressure on the distribution sector to the same extent as it would do on the transmission sector.

Gas selling prices

3.23 The way in which natural gas is priced for sales to distributors, large industrial users and power stations is a matter of considerable importance for the common carriage issue. First, gas buyers who take the view that they face gas prices of a discriminatory or monopolistic kind are perhaps most likely to seek the opportunity to deal direct with producers via common carriage. Conversely, the gas utilities who might be most affected by common carriage are those who might be considered to earn "above normal" profit margins on sales to some consumers or classes of consumers. An effective common carriage system might be expected to reduce existing price differentials between comparable gas users, both within and between Member States, and this further underlines the need to understand the present pricing systems. In this sub-section, an introduction to gas pricing systems in Member States is followed by a brief discussion of policies in the main gas consuming countries and a comparison of prevailing price levels as between Member States.

3.24 Depending on the organisational structure of the gas industry, we can distinguish three main categories of gas selling prices, as follows:-

(a) prices for sales from distributors (or, in the case of France and the UK, from the integrated national utility) to households and other small gas customers;
(b) prices for sales from transmission companies direct to large industrial or power plant consumers; and
(c) prices for sales from transmission companies to distributors (widely applicable in all member states except France and the UK).

Since it is almost inconceivable that individual small consumers could avail themselves of common carriage rights, it is categories (b) and (c) above which are of particular relevance to the present study. To put large user selling prices in context, however, it may be worth commenting briefly on arrangements for smaller consumers.

3.25 As mentioned above, <u>sales to households and other small customers</u> are generally made by distributors or, in the case of France and the UK, by the vertically integrated transmission and distribution utility. Such sales are almost universally made on the basis of standard, published tariffs, though in some countries (such as Italy and West Germany) there are considerable differences in the level of gas tariffs charged by different local gas distributors. Small user tariff arrangements frequently apply up to a certain threshold level of consumption, which varies from just 69,000 m^3/a in the UK, through to 880,000 m^3/a in Belgium, for example. In West Germany, there is no threshold as such and standard tariffs appear to apply only to very small (household size) consumers. Typically, tariffs for small users often tend to bear some relationship to the price of the nearest competing fuel, often light heating oil. Household gas prices in West Germany have recently reflected a small premium above those of gas oil, for example, while the Dutch "A" tariff for small users has reflected parity with gas oil since the oil price collapse in 1986. The level of distributors' costs may also be an important pricing consideration, especially where a "cost plus" approach is adopted for small users tariffs as in Belgium and Italy. Since distributors' gas purchase costs are often linked partly to alternative fuel prices, however, the total cost of supplying gas to small users may itself be broadly related to the price of competing fuels. In Belgium, the use of the border price of imported gas (the "G factor") as a key element in the tariff structure is a good illustration of this point. Where domestic/commercial gas markets are still expanding, however, gas prices may be set well below the alternative fuel to promote sales. In Italy, for example, taxes on heating oil are very high and small user gas prices have generally been substantially below gas oil prices in order to encourage changeover to gas. In general, Governments (national or local) often have an important say in the level at which tariffs are set, though in West Germany the authorities are not heavily involved in price setting. In the case of the UK, British Gas is subject to a formal regulatory price formula which is broadly based on costs of supply, but sets a target for improved efficiency in operations. Since the fixed costs per unit of supply (connection costs, meter reading and billing) are usually significant for smaller consumers, two-part tariffs (standing charge plus commodity rate) are very common for such users.

3.26 <u>Gas sales to larger industrial or power station users</u> are typically made direct by transmission utilities and the pattern of pricing systems is quite diverse. Among the main gas-consuming Member States, Belgium, France, Italy and the Netherlands have large user gas prices which are based to a large extent on published tariffs, while in the United Kingdom and West Germany these prices are based on the outcome of sales contract negotiations between the gas supplier and the individual large user.

Within the category of large users as a whole, it is often helpful to distinguish three sub-groups of large scale gas consumption, viz:

(a) "premium" industrial applications such as process uses for which a high quality, controllable fuel (gas oil, electricity, natural gas or LPG) is typically required;

(b) "non-premium" industrial applications such as steam-raising under boilers or auto-generation of electricity, for which natural gas typically faces competition from low value fuels such as heavy fuel oil (HFO) or coal; and

(c) very large volume uses of a specific nature such as gas feedstocks (for ammonia or methanol production) and gas use in power stations.

3.27 In many Member States, gas tends to be supplied on a firm basis to "premium" and smaller "non-premium" industrial customers. Large, non-premium industrial consumers are often supplied on interruptible terms and receive prices which are somewhat lower as a result. West Germany appears to be an exception in this regard, in that a significant number of large, non-premium customers are supplied with firm gas at prices which reflect the low-value competing fuel (HFO). Whether by tariff arrangements or as a result of individual contract negotiations, most large industrial user gas prices are linked in some way to the prices of competing fuels, usually oil products. In Italy and the Netherlands, for example, very little gas oil is now used in industry and all industrial gas prices tend to be tied in some way to HFO. Gas oil continues to play a more important role in "premium" industrial energy markets in the UK and West Germany and there tends to be a more pronounced distinction between prices for gas sales in competition with high and low value oil products (gas oil and HFO). In some cases, very large gas users such as power plants, ammonia or methanol manufacturers, may receive special terms, even where the other industrial users are subject to more transparent tariff arrangements. For feedstock sales, in particular, the lowest Dutch gas tariff (known as "F" tariff) is widely regarded as a marker for prices elsewhere in Western Europe. Sales to power stations take place on a very large scale only in Italy, West Germany and the Netherlands (typically 6-7 bcm/a in each case), although power plants account for a significant proportion of much smaller markets in Denmark and Ireland, for example. Much smaller volumes are also sold to the power sector in Belgium and no significant sales to public power stations at present in either France or the UK. Pricing systems for gas sales to large users vary considerably as between Member States and we therefore summarise the position in each case below, beginning with the six largest gas-consuming countries.

3.28 In Belgium, there are three categories of industrial gas supplies - firm sales, sales which are interruptible ("effacable") at the supplier's option only and supplies which are fully interruptible by either buyer or seller (known elsewhere as "mutual option" arrangements). "Effacable" contracts apply mainly to "premium" industrial customers who can nevertheless switch to an alternative fuel, although they have rarely been interrupted in recent years. The fully interruptible contracts are unusual in Europe in that they give the buyer an explicit contractual right to switch to other fuels at any time. The prices for all three categories of sales are based on a complex tariff system of which the most important element is the "G factor", the average Belgian border price of natural gas imported by Distrigaz. Other price elements are intended to reflect the non-gas costs of supply. Both the "G factor" and a non-gas element enter into the commodity rate and there are also indexed standing charges (for firm supplies only) and connection charges. Prices are progressively reduced at higher offtake levels and are effectively discounted for interruptibility. Tariffs are recalculated monthly but, as far as the "G factor" is concerned, reflect the escalation lags in Distrigaz purchase contracts between oil price movements and changes in the gas contract price.

3.29 When oil prices fell rapidly in 1986, the fully interruptible tariff then in force became uncompetitive with HFO (largely because of lags in the G factor and the fact that HFO prices tended to fall faster than those of oil in general) and Distrigaz lost a substantial portion of its interruptible load. The supervisory Control Committee (which includes trades union and industrial federation representatives as well as officials and gas industry executives) gave its consent for interruptible selling prices to fall below the G factor, so long as the variable element of the border price was covered. This was defined to be the commodity price of gas purchases at the point of supply (eg Emden, in the case of Norwegian gas), plus the commodity element of the tariffs paid by Distrigaz for the transportation of gas to the Belgian border. Capacity costs/charges - in the Dutch export contract or the transportation arrangements with other utilities - were excluded and this has enabled Distrigaz to recover a certain amount of the load lost in 1986.

3.30 From 1986, Gaz de France has been free to set prices for large industrial users in France, independent of explicit Government control. In principle, however, the charges are still published, non-discriminatory and consistent between different consumers. There are two uniform large user tariff bases known as ST, for customers located on the GdF transmission system, and higher SR rates for those located on the distribution grid. These apply to consumers taking more than 5m kWh (some 470,000 m^3) per year. Again, there is an annual fixed charge and there is also a maximum subscribed winter offtake charge. In the case of interruptible sales, there was a modification to the tariff system in response to lower oil prices and more intensive competition from HFO in 1986. GdF appears to have charged a gas price equivalent to the HFO price (plus a quality premium) to interruptible users over the last couple of years.

3.31 In Italy, large user prices are closely monitored by Government but the tariff bases are actually renegotiated periodically between SNAM and the industrial federations, Confindustria and Confapi. There are three tariffs for large users - high usage, low usage and flat rate - but the vast majority of SNAM industrial sales are covered by the high usage tariff. For firm customers, there is a maximum offtake charge and a commodity charge which is linked to Italian ex-refinery/coastal depot prices of high sulphur fuel oil and is progressively reduced on a sliding scale as consumption increases. Interruptible tariffs are linked to the same HSFO price but effectively discounted to bring them out somewhat below the lowest firm gas price. In view of its supply/demand balance and the need to promote additional gas use, SNAM has also offered a system of price discounts to new consumers and existing users who increase their consumption. These vary from around 3-4% for very large users up to around 20% or so for new firm consumers using less than 3 mcm/a. Sales to power stations have not generally been interrupted by SNAM and their price is linked contractually to HSFO prices, less a discount to make gas attractive to ENEL. Chemical feedstock sales are generally made on a firm basis but these consumers effectively get a lower (interruptible) price.

3.32 Gas tariffs in the Netherlands are among the simplest and most transparent in the Community. There are six "zones", or tariff blocks, at different consumption levels of which zone A (less than 170,000 m^3/a) relates to small users. Zones B to F relate to direct Gasunie sales to larger customers and are each related in some way to the "P factor", which is the Rotterdam spot market price of low sulphur fuel oil plus a transport cost element and fuel oil duty applicable in the Netherlands. The tariff formula in each case is such as to produce a progressively lower price as consumption increases through the zones, from B (170,000-1,000,000 m^3/a) through to E (over 50 mcm/a) and F (over 600 mcm/a). There is no load factor adjustment to the tariff rates, reflecting a 'market value' pricing philosophy in relation to fuel oil prices, which tend not to be very sensitive to the seasonal pattern of use. Gasunie's "F" tariff in fact applies only to ammonia and methanol producers and sets a marker price for feedstock sales to ammonia producers elsewhere in the Community, such as France, West Germany and the UK. It is understood that power stations in the Netherlands used to be charged at a special rate but that they are now encompassed within the general "E" tariff. Since there are scarcely any interruptible sales (other than for power stations), the same uniform tariff system is generally applied to all types of industrial gas consumer.

3.33 In the United Kingdom, the system is very different in that prices for sales to customers using more than 69,000 m^3/a (25,000 therms) are individually negotiated on a contract basis between British Gas and the customer. Broadly speaking, prices tend to reflect the price of the competing fuel to the individual user, usually gas oil for premium consumers and HFO for non-premium industrial users, adjusted for the relative in-use value of gas and the alternative. In most cases, this means that British Gas seek to obtain a price higher than that of the alternative fuel, especially where the consumer has no oil-burning facilities. Premium users are generally supplied on a firm basis, while large non-premium customers are typically sold gas on interruptible terms. Whereas tariffs for small users (below 69,000 m^3/a) are explicitly regulated, contract sales are subject only to maximum prices published by British Gas itself and the general competition law applicable in the UK. Recently, competition from HFO has exerted downward pressure on interruptible gas prices, as all interruptible consumers have dual fuel facilities and can quickly switch between gas and oil. Firm gas prices, on the other hand, vary more widely as the majority of premium industrial gas users have no installed capability to burn oil and many of the smaller ones pay prices at or near the published maximum. This pricing system has recently been investigated by the Monopolies & Mergers Commission (MMC). Reporting in October 1988, the MMC has now recommended that BG should no longer be permitted to discriminate in pricing or supply as between comparable industrial users, other than for feedstock sales. This is clearly a very significant change, which would make it easier for new entrants to compete with BG via common carriage, but it is rather too early to draw precise conclusions as to its practical implications for the UK market.

3.34 The situation in West Germany is highly complex as industrial gas sales are made by distributors as well as transmission companies. Prices are again determined by individual contract negotiation and there are considerable variations in the price levels and the structure of contractual price adjustment clauses from case to case. There appear to be four broad categories of industrial gas prices, in descending price order:-

(a) sales (generally on a firm basis) to premium customers with a gas oil alternative;
(b) firm sales to non-premium customers with an HFO alternative;
(c) interruptible sales to non-premium customers with an HFO alternative; and
(d) interruptible sales to very large users with a coal alternative (often power stations).

In general, all the gas sellers in West Germany adopt a market-related approach which sets the gas price in relation to the price of the competing fuel, plus a premium in the case of lower quality fuels such as HFO and (particularly) coal. This approach therefore leads to a wide range of industrial gas prices, especially for firm gas which is sold to both premium and non-premium users. Market-related pricing nevertheless appears to command a wide measure of support from bodies such as VIK, the association of large energy users, and the Bundeskartelamt (competition office), who take the view that inter-fuel competition is generally sufficiently strong to prevent an abuse of monopoly position by the gas utilities.

3.35 In Denmark, there are relatively few large industrial gas consumers (just over 200 in 1987) and these are supplied on the basis of a published tariff which links the gas price to a net-of-tax fuel oil price, since industrial users are not subject to the oil taxes paid by smaller consumers.

3.36 In the Republic of Ireland, smaller industrial consumers taking up to 150,000 therms/a (around $420,000m^3/a$) pay a relatively high published tariff which falls somewhat as consumption levels increase. Above 150,000 therms, prices are individually negotiated rather than published tariffs. Negotiations appear to take place on the basis of a relationship to the heavy fuel oil price, usually within the range 87.5% to 120% of fuel oil depending on the use of gas and the bargaining position. Although the number of large consumers is very small, electricity generation and fertilizer production alone accounted for nearly 90% of total gas demand in 1985.

3.37 In Luxembourg, many small and medium sized industrial consumers are supplied under a simple 2 part "THP" tariff (monthly delivery charge plus a commodity charge per m^3). Larger consumers (over 41860GJ or around 1 mcm/a) with a fuel oil stand-by can decide whether to be supplied under the newly introduced 'spot' tariff (related to fuel oil prices) rather than the THP tariff.

3.38 In Spain the situation is complicated by the fact that a distinction must be made between the tariffs of distribution companies and those of

ENAGAS who supply industrial consumers (in the north and east) directly from the gas pipeline. The former are simple two part tariffs with three levels of consumption. For larger industrial consumers supplied by ENAGAS, there are a number of different firm gas tariffs (depending on the end-use sector) and a single interruptible supply tariff (applied only to consumers over 41860 GJ or around 1mcm/a) which is somewhat below the average firm tariff level.

3.39 A summary of estimated gas prices to medium sized firm and interruptible gas consumers in the six main gas-consuming Member States over the last two years is set out overleaf in table 3.4. In some cases, precise information is not readily available but it is believed that the overall pattern of gas price estimates is broadly correct. The table shows that prices in Italy and the Netherlands have recently tended to be among the lowest in the Community, with relatively high prices (at least for firm sales to premium consumers) in Great Britain and West Germany. Significantly, the range of prices across Member States is generally much wider for firm sales (where competition from other fuels may be less intense) than for interruptible gas which generally competes quite closely with HFO at prices which, apart from differences in duty, do not vary all that widely from country to country. The very wide range of firm gas prices within West Germany reflects the fact that some large non-premium users are supplied with firm gas at HFO related prices, while premium users pay much higher prices related to gas oil. In other Member States, large non-premium customers would typically be supplied with interruptible gas. Another important point is that firm/interruptible price differentials tend to be lower in Member States (such as France and Italy) with access to substantial amounts of low cost gas storage. Where storage is less plentiful (as in the UK or West Germany), the cost of providing peak winter supplies will tend to be higher and this may be reflected in a greater price differential between those customers who are supplied all year round and those who can be interrupted in the winter peak.

3.40 Turning to <u>sales from the transmission companies to distributors</u>, a number of different arrangements have again developed in the various Member States. Typically, the transmission company is seeking a positive trading margin, after allowing for its gas purchase costs, transmission

Table 3.4: European industrial gas prices in ECU/m^3

(load sizes 3-28 mcm/a)

	October 1986	February 1988	Note
Firm gas			
Belgium	0.14 - 0.15	0.11 - 0.13	(1)
France	0.14 - 0.16	0.12 - 0.14	(2)
Italy	0.09 - 0.10	0.08 - 0.09	
Netherlands	0.07	0.10	(3)
United Kingdom (GB)	0.14 - 0.18	0.14 - 0.18	
West Germany (a)	0.10 - 0.11	0.10 - 0.11	(4)
West Germany (b)	0.19	0.15	(5)
Interruptible gas			
Belgium	0.13	0.09	(6)
France	0.13	0.11	
Italy	0.08	0.07	
Netherlands	-	-	(7)
United Kingdom (GB)	0.09	0.09	
West Germany	0.09	0.09	

Notes:

(1) tariff for 6 mcm/a; variations reflect load factors and nature of use

(2) range reflects load size, load factor and location

(3) based on Gasunie C/D tariffs

(4) HFO related contracts

(5) gas oil or mixed GO/HFO contracts; middle of a wide price range

(6) price for fully interruptible (mutual option) supplies

(7) no interruptible sales to customers in this size band

Source: Confederation of British Industry (October 1986); estimated for February 1988 costs, administrative expenses and the cost of any other services provided, such as gas storage used to convert high load factor gas purchases into a lower load factor supply to the distributor. Since transmission companies often sell direct to large industrial consumers themselves, most distributors will have a market mix which is biased in favour of household and other small consumers. Such consumers tend to have high value alternative fuels (gas oil, electricity) and can thus pay relatively high gas prices, but their size and the highly seasonal pattern of their demand also makes them more expensive to supply. Thus the distributor will usually incur a relatively high level of non-gas expenses and will be looking for a gas purchase price sufficiently below the average netback from sales to final consumers to provide a reasonable profit. Commonly, therefore, gas is sold from transmission companies to distributors at some margin below the price of gas oil and prices often tend to move broadly in line with gas oil over time. Provided the transmission company's gas purchase costs and the distributor's market realisation maintain a reasonably stable relationship, the objectives of each can generally be satisfied, but if they do not then there is automatically a conflict over the burden of losses resulting from misalignment. This arose in some cases in 1986, for example, when competing oil prices fell rapidly while bulk gas purchase prices were reduced only more slowly due to the lags in purchase price escalation clauses.

3.41 Frequently, prices for bulk sales from transmission companies to the distributors are negotiated by the association of gas distributors on behalf of its members, as with VEGIN in the Netherlands, for example. However, such arrangements tend to be closely monitored by Government - by the Ministry of Economic Affairs in the Netherlands, the Interministerial Pricing Committee in Italy or through the gas and electricity Control Committee in Belgium. Within the last two years the Dutch Government has, for example, intervened to stipulate more gradual price reductions in small user gas prices (and in the price paid by VEGIN to Gasunie) than the two organisations had agreed, in order to protect the revenue which it obtains from the gas industry through the financing and taxation arrangements for producing company NAM.

3.42 In Belgium, sales from Distrigaz to the local distribution companies are supervised by the Control Committee and there is a uniform "cost plus" tariff system in place for all distributors. Sales are made at the "G" factor (average border price of gas imports), plus a non-gas cost element plus a margin for profit, recalculated monthly using the indexation mechanism incorporated in the tariff. There is no capacity charge to be paid by the distributors and no take-or-pay, so that they effectively get whatever gas they require. The Control Committee also supervises profit levels in the gas industry and would have the power to require tariff reductions if Distrigaz profits appeared to be excessive.

3.43 In the Netherlands, the prices at which gas is sold from Gasunie to local distributors largely reflect the gas oil parity price at which distributors sell to small end-consumers, less a distribution margin. However, the distribution margin is set for each distribution company in accordance with a formula whereby the margin allowed is inversely proportional to average consumption per gas connection. Thus distributors with a low average consumption per connection are assumed to have high distribution costs and obtain gas supplies at lower cost from Gasunie; purchase prices can vary by as much as Gc $4/m^3$ (just less than ECU $0.02/m^3$) from the lowest to the highest. There is no distributors' take-or-pay commitment to Gasunie and no capacity charge; Gasunie also has to make sufficient 'L' (low calorific value) gas available to meet their needs as they cannot safely distribute 'H' gas. These arrangements are covered by a rolling 15 year "evergreen" contract under which the distributors are obliged to purchase all their requirements (some 20 bcm/a) from Gasunie.

3.44 In Italy, there is a uniform, published tariff system for sales from SNAM to the 2000 local distribution companies. This is negotiated periodically between SNAM and the distributors' representatives, but is subject to approval by the Interministerial Pricing Committee (CIP). The current arrangement includes a commodity charge, which is indexed with changes in gas oil prices, and a capacity charge which is indexed with non-energy inflation. Prices are recalculated every 2 months, with unusually short escalation lags of only 6-7 weeks on average. The distributors are then allowed to set "cost plus" prices for small gas consumers which vary from commune to commune in line with a formula incorporating cost parameters such as the average level of consumption per gas connection.

3.45 In Denmark, there is yet another system to reflect the fact that transmission company Dangas do not sell to any final consumers apart from power stations. For each market segment (small users, district heating, industrial consumers) which is supplied by the distributors, there is a separate gas price from Dangas. An overall gross margin was estimated for each market from the sales revenue in that market, minus the corresponding gas purchase costs under the contract between Dangas and producer DUC. The gross margin was then shared out between the distributors and Dangas on a two-thirds/one-third basis in order to establish the Dangas selling price and this selling price is indexed with gas oil or fuel oil prices, as the case may be.

3.46 In West Germany, prices to distributors are not directly controlled by Government, but for reasons of competition law there is essentially one supply and pricing system for all distributors. This involves a firm gas supply, with separate capacity and commodity charges and prices which reflect the average netback across all the distribution companies. Capacity and volume requirements are discussed in advance, but the distributors are required to give no contractual capacity subscription or take-or-pay commitment as such. Ruhrgas and others sell to distributors under long-term 20 year contracts, but with the right for either party to reopen price discussions if the market situation has significantly changed. Similar principles, with a number of negotiated differences, apply to sales from Ruhrgas and BEB to the various regional gas transmission companies in West Germany. There have been a number of changes in the terms of sale from Ruhrgas and others to local utilities in the last year or two - including a trend away from a mixed basket of price escalation to 100% gas oil escalation, an increase in the frequency of price revision from every 6 months to every 3 months and the introduction of a "substitute commodity price" when oil prices are very low to protect the transmission company's margin to some extent. When oil prices are falling, the more frequent price revisions would tend to act in favour of the distributors, ensuring that gas costs fall in line with market realisations, but could mean that gas costs will rise more quickly at a time of rising oil prices in the future.

3.47 An important issue is the relative level of profits which transmission companies earn on sales to their own industrial customers and to local distributors. In general, selling prices to distributors tend to be above the average selling price to industrial customers - particularly in Member States where practically all industrial sales are made at HFO-related prices. It might be argued that industrial markets, where a substantial proportion of users have a dual-firing capability, are characterised by more intense inter-fuel competition than small user markets, where consumers tend to make less frequent fuel choices at the time fuel-using appliances are replaced. Thus, particularly when oil prices are falling, there might be a tendency for transmission companies to reduce industrial gas prices relatively rapidly - squeezing margins but at least retaining load - but seek to maintain higher margins on sales to distributors. In the Member States examined above, it seems that distributors' margins are generally quite well protected, except where they are inefficient and incur higher costs than the tariff system was designed to cover. They may nevertheless continue to provide a relatively high margin sales outlet for transmission companies, especially where capacity costs are low, as in the Netherlands. Some distribution companies might therefore consider the current margin excessive, though it must be added that the contractual flexibility they enjoy on both capacity and offtake volumes is much greater than they could expect if they tried to buy direct from producers for themselves. The present arrangements might also be questioned from an overall efficiency point of view, since in some cases they leave little incentive for distributors to market effectively and operate efficiently to reduce their own costs and those they impose on the gas system as a whole.

3.48 Although transmission company sales to distributors are, in many Member States, "policed" by the Government, the intervention of the Dutch authorities in recent years suggests that Governments cannot necessarily be relied upon to look after distributors' interests. Similarly, the fact that Bayerngas was sufficiently aggrieved to seek a direct purchase and than take its case to the European Commission suggests that at least some local/regional utility buyers have felt their treatment was not altogether equitable. When it is considered that there now appears to be a relatively narrow band of European gas purchase prices across different Member States and the various different exporting countries, the sheer variation in gas selling prices observed in the Community as between comparable purchasers is at least suggestive of some monopoly profit element in prices to some consumers or classes of consumers which a more open internal gas market might conceivably squeeze out of the system. Whether this would simply mean higher gas prices to other consumers or categories of consumers is a question we will return to in Section V below.

Market developments

3.49 In order to assess the probable impact of a system of common carriage it is important to identify those gas consumers most likely to take advantage of such a system. There are several factors which may influence the extent to which an individual consumer could benefit from a system of common carriage, including:

(a) location on the system (i.e. on the transmission or the distribution grid);
(b) size of the consumer;
(c) load factor; and
(d) the availability of a stand-by fuel, which may allow the consumer to negotiate gas transportation on an interruptible basis.

3.50 Large consumers located on the transmission grid with a high load factor are relatively well placed to take advantage of a system of common carriage. This is partly because such loads would be cheaper and easier for producers to supply direct than other types of consumer, and partly because these large consumers may have the negotiating strength and skills required to deal direct with producers. In this sub-section, a short summary of the developments in gas demand over the last twenty years is followed by an assessment of the three main consumer categories - small residential/commercial users, large industrial users and power plants. We examine the likely development of gas demand in each of the categories and seek to draw some preliminary conclusions regarding the likely reaction to a common carriage system.

3.51 In the last twenty years, gas has more than doubled its percentage share in gross inland energy consumption in the EC countries (from 9.1 per cent in 1971 to 19.2 per cent in 1985). The increasing importance of gas in overall energy consumption has been a phenomenon common to most EC countries, but the pattern and extent of this growth has been somewhat different in the different Member States. Common to most countries has been the rapid growth in the residential/commercial sector which has increased its share of total gross inland gas consumption from 31% in 1973 to 50% in 1986. In the more "mature" gas markets, industrial gas demand tended to grow quite rapidly in the 1970's but the growth rate has generally been much slower in the 1980s. In relatively "young" gas markets (eg Spain) or in countries where the gas grid has undergone significant recent extension (eg Italy), however, quite rapid growth of gas consumption in the industrial sector has continued into the 1980's.

3.52 Of the three main demand sectors - residential/commercial, industrial and electricity generating - the <u>residential/commercial sector</u> has experienced the fastest rate of growth. Consumption more than doubled over the period 1973 - 1986. This was mainly due to the development of gas for space heating in the more mature markets (Britain, W. Germany, France and the Benelux countries). In other markets (eg Italy, Spain), the increase in demand in this sector also reflected the expansion of the gas infrastructure and the ability to offer gas to new consumers who previously had no access to the grid.

3.53 The typical consumer in the residential/commercial sector is small (around 2000-3000 m^3/a for a domestic central heating user) and connected to the distribution grid. The most common applications for gas are space heating, water heating and cooking, which implies a low load factor (seasonal in the case space heating, and daily in the case of cooking and water heating). Of these, space heating is quantitatively the most important in most countries. In the majority of the Member States, gas faces competition in this market principally from light heating oil and in some cases from electricity (UK, France). In some West German cities and in Denmark, for example, certain areas are reserved for district heating, but there is not generally direct competition for customers between gas and district heat. Few small commercial customers and almost no household consumers have installed capacity to switch fuel at short notice. Gas supplies to this sector are almost exclusively made on a "firm" (non-interruptible) basis. Given the relative high appliance cost (compared to fuel costs) and the long life of appliances, consumers tend to be linked in to one particular fuel for a considerable length of time. This implies a stable customer base, although demand can nevertheless fluctuate from year to year for weather-related reasons, and means that in the short-medium term, small gas consumers are effectively captive to the industry.

3.54 Simply because of their size, it is inconceivable that individual small consumers in the residential/commercial sector will benefit directly from a system of common carriage. They might benefit indirectly, however, since local distribution companies might take advantage of common carriage and the benefit could trickle down, through price reductions, to the individual small consumer. Experience in the UK also suggests that groups of larger "commercial" sector users, such as local government authorities, might conceivably be in a position to attempt to purchase direct from producers.

3.55 Further growth in demand in this sector will depend on the extension of the infrastructure in the relatively "young" gas markets and the increased use of gas for space heating in the mature markets. Demand forecasts used by the European Commission show an increase in gas consumption of around 15 per cent in total between now and the year 2000. The fastest growth rates in residential and commercial gas demand are expected in the relatively young markets such as Ireland, Spain and Denmark. In the Netherlands, on the other hand, gas demand in this sector is expected to stay approximately constant.

3.56 In the <u>industrial sector</u>, gas consumption in Member States grew by more than 30 per cent in the 1970s. In the early 1980s, however, gas lost most of its gains made in the previous decade due to a reduction in energy-intensive economic activity, increased energy efficiency and, more recently, a fall in the price of fuel oil. In analysing gas demand in the industrial sector one needs to distinguish between three quite distinct types of gas consumption:

(a) 'premium applications';
(b) 'non-premium applications'; and
(c) feedstock uses.

3.57 Gas used for 'premium applications' competes with high value alternative fuels such as gas oil, LPG and electricity. In general, the fuel used needs to be clean and easily controllable since the most common applications of gas in this category are direct firing (heating of metals, baking etc) and space heating. Load factors can vary very considerably but may on average lie in the range of 50-60 per cent. Although most consumers of this type are much larger than domestic users, very many do not use more than a few million cubic metres of gas per year. A high proportion of "premium" industrial gas use tends to be accounted for by a few very large process users, of which the steel industry is perhaps the single most important example. In the main, premium industrial users do not tend to have installed capacity to use any alternative fuel to gas and are therefore supplied on a firm basis.

3.58 The most common 'non-premium application' is raising steam in large boilers, though industrial auto-generation of electricity is another important end-use in this category. Gas tends to compete mainly with fuel oil, or in some cases to a lesser extent with coal (for example in W. Germany and the UK). Non-premium industrial consumers tend to be much larger than most premium consumers and some large chemical companies may consume up to several hundred mcm per annum. In almost all cases, steam-raising customers have installed capacity to use other fuels (generally fuel oil) and are therefore frequently supplied on an interruptible basis. There are, however, exceptions such as large firm gas deliveries to chemicals companies with substantial steam-raising and auto-generation requirements in West Germany. Many large non-premium industrial users are located on the medium, if not high, pressure transmission grid.

3.59 In a number of major gas-consuming countries, a significant percentage of total industrial demand is accounted for by a few very large feedstock consumers. These consumers often take several hundred mcm/a and ICI in Britain may use as much as 1 bcm/a for feedstock purposes. In most cases, gas feedstocks are used in ammonia/fertilizer or sometimes methanol plants. They tend to be connected to the transmission grid and to have a high load factor. Some such plants are in a position to use propane as an alternative to natural gas. In most cases, however, the main alternative to using gas would be to suspend production of methanol/ammonia and purchase product from other suppliers for further chemical processing. Gas supplies are mainly firm, though there are some interruptible feedstock supplies (as in the United Kingdom), especially where a propane alternative exists.

3.60 The changing industrial structure in Europe and the trend towards high-value, non-energy intensive industries, together with the adoption of more energy efficient technologies, is likely to mean at best a slow growth in industrial gas demand, at least in the 'mature' gas markets. Demand in the premium industrial market may be relatively stable, with some growth prospects as more industrial users go over from indirect (steam raising) process use to more efficient direct heating, for which low grade fuels such as HFO are unsuitable. However, demand in the non-premium/interruptible market may fluctuate more sharply with the price of fuel oil, as has happened over the last few years. In the feedstock sector, the most efficient European plants are likely to continue in operation, but increasing competition from low cost gas producing countries (e.g. in the Middle East) could lead to the closure of older, less efficient plant in Europe. In the newer European gas markets, there is still considerable scope for expansion in the industrial sector. Many of the countries planning a significant development of new or much expanded gas industries are now very dependent on imported oil (e.g. Greece and Portugal). Gas development is seen as a way to diversify a country's fuel mix and industries will therefore be encouraged to start using gas. In the forcast used by the Commission, total industrial gas demand in the Community is expected to increase by around 60 per cent from 1986 levels before the end of the century. A significant proportion of the increase is represented by a rise in consumption in the newer markets (such as Denmark and Spain). Nevertheless, the overall forecast seems rather optimistic.

3.61 Of the three types of industrial consumers, feedstock users are relatively well placed to take advantage of the introduction of common carriage. Feedstock prices in N.W.Europe tend to be quite similar, since the Dutch "F" tariff is widely regarded as a price marker. The companies in the ammonia business are faced with international competition, however, and are concerned about relative feedstock costs outside Europe. Arguably, the HFO-related "F" tariff does not really address their need to remain competitive and they might be keen to try to buy direct from producers, in order to cover themselves against a fertilizer market downturn. Nevertheless, the extent to which a system of common carriage would enable them to negotiate further price reductions might be limited since they are already charged the lowest prices in the industry. Large non-premium users (eg major chemical companies) might also be considered relatively well placed to buy gas direct from producers via common carriage. Like the feedstock consumers, however, they are often charged relatively low prices with few large variations in price across the different Member States. Energy-intensive non-premium users would be keen to see gas-to-gas competition in the hope that industrial gas prices might fall <u>below</u> those of the competing fuel. Whether gas producers would be prepared to offer discounts in this way is an open question to which we return in section VI.

3.62 The biggest variation between the gas charges across the different Member States are those to premium/firm customers. This indicates that those paying much more than average have the most to gain from the introduction of common carriage, but as mentioned before many such customers would not, taken individually, be large enough to be able to buy gas direct. Industrial consumers who could not individually take advantage of common carriage might, however, benefit through the formation of purchasing consortia or emergence or marketing/trading companies as occurred in the US. In the UK, the AHS/Hadsons joint venture Associated Gas Supplies is also seeking to develop this kind of role for itself via common carriage.

3.63 Demand for gas in the <u>electricity generating sector</u> fell in the 1970s and early 1980s and has only recently started to grow again. In part, this reflected the increase in oil and gas prices relative to those of other fuels from 1973 through to the early 1980s. Part of the reason for this decline in demand has also been political decisions to restrict the use of gas for power generation, often to protect the coal industry as in the

United Kingdom and West Germany. In 1975, the European Community adopted a Council Directive limiting the use of natural gas in public power stations. It says that gas has great advantages for certain specific uses and should, consequently, be converted into electricity only when it can not be used for other purposes, except in cases of technical or economic necessity, or in certain circumstances to protect the environment.

3.64 Currently, quite large amounts of gas are being used for power generation in Italy, the Netherlands and West Germany. In Italy, natural gas consumption by ENEL has been increasing as a result of surplus contracted gas supplies (in relation to progress with grid development) and a related policy of substitution away from fuel oil. In the Netherlands, relatively low cost indigenous gas has been competitive vis-a-vis imported coal and oil. In both countries, environmental opposition to other forms of generation (nuclear and coal) has also played a role in the importance of gas fired generation. Up to the late 1970's, W.Germany still used very considerable quantities of gas for power generation. Since 1979, however, there has been a significant reduction in the use of gas and priority has been given to indigenous coal and to a lesser extent nuclear. West Germany now uses some 7 bcm/a of gas in power stations, mainly for middle/peak load purposes. In the UK, gas has scarcely been used for public power generation, due to a policy of protecting British Coal, the perception of gas as a 'noble fuel' which should not be used for power generation and, until the late 1970s at least, a scare natural resource which should be reserved for higher value purposes. France does not have a history of using gas for power generation either. In the 1970's oil was predominantly used, but at present it is mainly nuclear.

3.65 Several factors have led to a recent revival of interest for using gas in this sector:

(a) less concern, on a political level, with the depletion of gas reserves. This is a result of the discovery of new gas fields and a considerable increase in the world's proven gas reserves. (Since 1975 they have gone up by more than 60 per cent);

(b) popular pressure to abandon or decrease in scope national nuclear programs in the wake of the Chernobyl disaster;

(c) the changed relative energy prices. The recent reduction in the price of gas has made the option of using gas for electricity generation much more attractive; and

(d) technology advances. Recent technology advances have changed the position of natural gas and made it a more competitive as a base load fuel. Of particular importance are the development of combined-cycle systems which can achieve fuel efficiency of 45% or better. If waste heat can also be used productively as parc of industrial or municipal CHP, then overall thermal efficiencies of 75% or more are obtainable.

3.66 Several countries, including the UK, Denmark, Belgium and the Netherlands, are seriously considering the option of introducing further gas generators. In the Netherlands SEP, the association of Dutch electricity generators, is planning to build two new 600MW gas-fired stations. These would be fuelled under a 25 year contract with Statoil for 2 bcm/a year from the mid-1990's. Significantly, the price of Norwegian gas will be linked partly to the price of coal and partly to the rate of inflation. Statoil's willingness to agree to coal price indexation significantly enhances the attractiveness of gas and might lead to a substantial increase in the use of gas in electricity generation, as many power utilities now perceive coal to be the closest alternative fuel. In the forecast used by the European Commsision, demand in this sector is set to fall by more than 40 per cent before the end of the century. Since the preparation of this forecast in July 1987, the attitude towards using gas for power generation has significantly changed, as outlined before, and the forecast therefore seems much too pessimistic. Some increase in consumption in this sector now seems more realistic.

3.67 Power stations are ideally suited to take advantage of a system of common carriage. They are very large consumers with a high load factor, are linked to the high pressure transmission grid and are capable of receiving interruptible supplies. In West Germany several power generation companies (eg. RWE, EWE, and VEW) have been buying directly from Gasunie for many years. In Britain, the combination of the introduction of common carriage and the forthcoming privatisation of the electricity sector has led to considerable interest by both would-be independent power generators and existing utilities in gas generation. A number of them are considering either supplies from British Gas or a direct purchase from North Sea producers.

3.68 Most forecasts now indicate that total Community gas demand will grow up to the year 2010 but not as fast as during the period 1970-85. In the forecast used by the European Commission, total gas consumption is expected to increase on average by just under 2 per cent per annum through to the end of the century.

Supply Developments and Supply/Demand Match

3.69 On the supply side, the main development over the last 15 years has been an increase in the number of supplier countries. In 1973 the Netherlands were the only important exporter of gas to Member States. In 1988 most EC countries can choose between four main sources of imported supply: Algeria, Norway, USSR and the Netherlands.

3.70 Of the four main exporting countries the Netherlands is the one with the smallest reserves. Its most significant gas reserves are found in Groningen. The Groningen field has been the major source of supply of gas in the Netherlands since its discovery and development in the early 1960s. In the 1960s nearly all gas sold by Gasunie originated from this field. More recently the importance of the Groningen field in total Dutch gas supply has fallen to only around half of all gas sold. The question of Dutch reserves has created some uncertainty in the past and until the early 1980s it had been widely assumed that by the year 2000 Dutch gas exports would decrease to zero. Due to revised gas reserves estimates and the subsequent change in export policy, gas exports were extended in 1984 and are now expected to continue well into the next century. However, future export levels will not be above the present level of supply and might very well be below this. Gasunie has a first right of refusal over all gas produced in the Netherlands and it has been helped in its marketing efforts to sell gas to European gas utilities by the flexibility of the Groningen field. This enables Gasunie to let the purchasing utility choose the load factor at which it wants to be supplied. Thus SNAM have tended to take

Dutch gas on a higher load factor (having extensive storage capacity) than Distrigaz, for example, who have relatively little storage capacity of their own. The depletion of the Groningen field and the consequent lowering of the pressure in the field might make production less flexible and therefore decrease the flexibility of supplies from Gasunie. At present Gasunie supplies W.Germany, France, Belgium, Italy and the Dutch seem unlikely to want to boost their gas exports above current levels, in order to reserve Groningen gas for the domestic market in the longer term.

3.71 The Soviet Union is the largest producer of natural gas in the world today. The country has also by far the largest proven gas reserves in the world (probably more than 75 per cent of the world's total reserves). The sheer size of the Soviet gas industry quite easily leaves room for export volumes to the West. In 1987, for example, the Soviet Union produced nearly 730 bcm of natural gas of which only about 5% was delivered to customers outside the Eastern bloc. Gas exports have considerable significance to Soviet foreign trade and account for about a fifth of Soviet-hard currency revenue from export to Western industrialised countries. In the long run the Soviets will definitely be interested to increase their market share, and the present relaxation in East-West relations might help the Soviets to do so. Production capacity is effectively unconstrained, although a very significant increase in exports would probably require an increase in transmission capacity across the USSR and Eastern Europe. So far Soviet exports into Europe have been voluntarily restricted by most gas utility buyers to an informal ceiling of 30 per cent of the total gas supply in any Member State. It is not clear to what extent this informal quota will continue to operate in the future. In the short run the Soviets are seeking to start selling gas in Spain and some of the smaller markets such as Greece, Turkey and Sweden (those countries where they sell significantly less than 30 per cent of total supply).

3.72 Algeria is the world's sixth largest gas power, with estimated reserves of 3,100 bcm. Originally only a LNG supplier, Algeria now also supplies natural gas to Europe through trans-Mediteranean pipeline. In terms of reserves, the country's potential for further expanding its role in international gas trade is obvious, as are its needs for doing so. Oil reserves are declining, and by the turn of the century Algeria is expected to be using all its oil production for domestic purposes. That leaves gas exports as the important source of foreign earnings. The importance of gas (and oil) as a foreign currency earner has been highlighted by the recent economic and political turmoil in the country. The economic hardships which the country is currently suffering can be partly explained the recent fall in oil and gas prices. Algeria is therefore likely to be keen to increase gas exports wherever it can.

3.73 The development of Algerian gas exports has by no means fulfilled the expectations raised in the 1960s and 1970s when exports was projected to a 'peak annual volume of more than 70 bcm by the mid 1980s, more than three times the present actual annual export volume. Even now, Algeria is reported to have an export capacity of up to 46 bcm/a, as against only about 20 bcm/a which is actually sold. In the short to medium term, therefore, Algeria does not face any binding capacity constraint on increasing sales. Existing customers include Belgium, France, Italy (through the Trans-Med pipeline, not LNG), and Spain. Contracts have also been concluded for LNG sales to Greece and Turkey, though deliveries have yet to commence. Algeria is even prepared to make available boatloads of LNG on an option basis with no buyer's take-or-pay commitment, as the current arrangement for winter deliveries to British Gas illustrates. Future growth in exports will largely depend on Algerian's pricing policy for natural gas, which in recent years has been highly controversial. The principle of linking the price of gas to official crude oil prices led, for a period, to particularly high Algerian prices compared to other suppliers. In 1986, Algerian negotiators appeared to be prepared to adapt to recent developments in the market, and seemed intent on increasing their market share. More recently, however, the contract price billed by Sonatrach has been above the market level once again - leading to protracted disputes with both Gaz de France and Distrigaz. Thus the experience of European gas utilities with purchases from Algeria has made them reluctant to become too dependent on the supply of Algerian gas.

3.74 Commercial production of natural gas in <u>Norway</u> has a fairly short history. The first volumes from the Ekofisk and Frigg fields started to flow through pipelines to West Germany and Great Britain in 1977. The Norwegian gas market received a significant boost with the discovery of the

Troll field in 1979 which is of comparable size to the Groningen field. A big difference between the two fields is in the cost of extracting the gas. Gas from the Groningen field is relatively cheap to extract, being an on-shore field. In contrast, the Troll field is a difficult geological structure located at a water depth of 320-350 metres with a soft sea bed, and consequently the cost of extracting the gas is significantly higher. Total production is expected to reach 30 bcm in 1988. In the late 1970s and early 1980s Norwegian gas exports benefited greatly from competition between British and continental European buyers and from favourable market conditions. Norwegian deliveries were considered strategically important to replace Dutch gas and to fill the perceived gas in supply. Norwegian gas will also, in the future, continue to expand in the European gas market. Recent marketing efforts by Statoil have resulted in gas contracts with SEP (the association of Dutch electricity generators), Spain and Austria. Further efforts are made to start exporting gas to Denmark and Sweden. Especially in view of declining sales to the UK and lower gas prices since 1986, the Norwegians are likely to be very keen to find new markets for thier gas. The Norwegian reserve base sets no limits to exports in the foreseeable future and Norway's geographic and political location in Western Europe will remain an asset. At some point in the 1990s, it is by no means inconceivable that Norway could decide to apply for membership of the Community and this might well bring advantages in terms of being able to market its gas, especially if a common carriage system is established.

3.75 Libya was an LNG supplier to Italy in the past, but proved somewhat unreliable and has only been delivering to Spain in recent years. Other possible future suppliers to the European gas market are Nigeria, Qatar and Iran. Only Nigeria has initiated preliminary export negotiations with various continental European buyers for about 5 bcm/a. Their main target customers are in West Germany, France, Spain, Italy and Belgium. Qatar has been discussing potential LNG exports to France and West Germany in the 1990s. Iran has been offering to export gas to Turkey with the ultimate export target being Western Europe.

3.76 The precise conditions under which the gas is sold by the producer to the gas utility, as outlined in the gas purchase contract, can differ significantly between one contract and the next. There are some features, however, which are common to most gas purchase contracts:

(a) long term agreement on volumes to be bought and sold;
(b) take or pay commitments;
(c) netback pricing, often with periodic (3 yearly) price reviews on this basis; and
(d) indexation with a basket of competitive fuels.

3.77 In nearly all cases the contracts are <u>long term</u> agreements. It is not uncommon to have contracts with a duration of up to 25 years. This is considered to be beneficial by both the producer and the purchasing gas utility. The producer will seek a guarantee that he can sell gas over a long period of time and thereby recoup the significant investments made in the development of the gas field. The utility will want to ensure that it can meet the demand requirements of its consumers.

3.78 Another common feature of gas purchase contracts is a <u>take-or-pay</u> commitment by the gas utility. The utility commits itself to buying a certain amount of gas per annum (the "minimum bill" quantity) and has to pay for this quantity whether or not it actual needs it. There are different degrees of take-or-pay commitment. A 100% take-or-pay commitment implies that the utility has to pay for the full Annual Contract Quantity (ACQ) set out in the contract. More common is an arrangement where minimum and maximum quantities of gas are agreed and the utility has a take-or-pay commitment with regard to the minimum quantity. For example, Soviet contracts typically allow flexibility within 80-110% of the ACQ; the Troll deal includes a range of 85-105%, with an extra 5% in either direction under defined weather conditions.

3.79 The price which the utility is willing to pay the supplier will depend on the price the gas utility can obtain for the gas from its consumers. In many cases the price the utility pays the supplier is based on <u>netback pricing</u>. The price Gasunie pays, for instance, for the gas it buys from NAM is related to the price Gasunie gets for its gas from the consumers. The difference between purchase price and sales price allows for Gasunie transmission costs and a certain profit margin. This implies that the producer will receive the economic rent but will also have to bear the risks of price fluctuations. Common to most contracts is that the gas prices will be subject to indexation which is designed to ensure that gas prices stay in line with those of alternative fuels.

3.80 The projected increase in Community gas demand can easily be met by Europe's current producers and suppliers. Of the four largest suppliers to the Community, the Netherlands will probably decrease its market share. The other three suppliers have very significant reserves (proven reserves to commercial production ratios of over 50 years) and would have little difficulty in delivering considerably more gas than at present. It seems unlikely that the current supply situation, with four main sources of supply, will change significantly over the next two decades. A system of common carriage might, however, lead to more instense competition for market share.

Comparison with the US situation

3.81 As mentioned in section I of the report, there are very few precedents in the world for the introduction of a common carriage system for the transport of natural gas. The most significant examples are the United States and the United Kingdom and, of these, only in the United States does third party transportation actually take place. Currently, around half of the gas volume moving through US interstate pipelines is being transported for third parties under Federal Energy Regulatory Commission (FERC) Open Access Orders, rather than having been bought from producers by the pipeline company for subsequent sale to distributors or large end-users. This very significant use of third party transportation - albeit on a voluntary rather than a mandatory basis - has led some observers to suggest that there might well be scope for similar development of direct marketing and competition between gas suppliers in the European Community. Having now examined the current and likely future gas supply situation within the Community itself, it may therefore be helpful at this stage to outline the very significant differences in the gas supply situation in the US.

3.82 In the context of common carriage, the most important contrasts between the US and EC gas supply situations relate to:-

(a) the number of gas producers and the typical level of gas production costs;
(b) the extent of the transmission pipeline infrastructure;
(c) recent trends in gas demand and the consequences of this for pipeline utilisation;
(d) the degree of self-sufficiency in natural gas and the sources of supply;
(e) the energy policy framework and degree of government intervention; and
(f) the legislative, administrative and regulatory regime in force.

In the following paragraphs, we comment briefly on each of these aspects in turn. a production cost point of view.

3.83 As we have already noted, there are essentially four main suppliers of natural gas to continental Western Europe - Gasunie (the Netherlands), Norway, Algeria and the Soviet Union. In some cases these are supplemented by producers of indigenous gas supplies, but the number of significant gas suppliers generally remains low. Even in the UK, where international oil companies supply gas from North Sea fields, the top 10 suppliers have recently accounted for around 80% of total gas supplies. In the US, by contrast, there are literally thousands of indigenous gas producers and almost 40% of production is accounted for by relatively small independants rather than oil company majors. Nor are the largest suppliers dominant in size as they are in the case of deliveries to Western Europe; for example, Shell and Exxon are the largest producers but each still only accounts for around 4-5% of the market. This suggests that gas producers/suppliers may have less market power than in the case of Western Europe and also helps to explain the emergence of US trading/marketing companies who have no production interests themselves but act as "brokers" in respect of third party gas transportation.

3.84 In the United States, some 60-65% of gas reserves lie onshore in the lower 48 states (principally Texas and Louisiana) and further supplies are available from the relatively shallow waters of the US Gulf. This means that, in general, costs of gas production tend to be relatively low. By contrast, a significant proportion of gas supplied to Member States is relatively expensive to produce and deliver - due to offshore operations in the North Sea, for example, sulphur removal from sour gas produced onshore in West Germany, liquefication and regasification of LNG supplies from Algeria or difficult operating conditions and high transport costs in the case of gas from Soviet Siberia. Groningen and other onshore gas production in the Netherlands is probably the only very major source of gas supply to Western Europe which might be regarded as broadly comparable with US onshore supplies from a production cost point of view.

3.85 There are also significant differences between the US situation and that of Community Member States in terms of pipeline infrastructure and capacity utilisation. Particularly from the main producing US states of the south and south-west to the major centres of consumption in the more densely populated and industrialised north-east and cities around the Great Lakes, there are often several different interstate gas pipelines (owned by different pipeline companies) through which gas can be supplied to the same locations. It has been estimated as much as 84% of the gas moving through the interstate system is subject to competition from other pipelines. (On the other hand, many smaller distributors are effectively "captive" and two-thirds of them are reported to have no choice of pipeline company supplier). In the Community, with a somewhat larger population but a much smaller land area than the US, there is frequently only a single high-pressure transmission line and invariably only a single transmission company serving any particular market area. Thus the US situation may exhibit a degree of competition between pipeline companies and a choice of bulk supplier for distributors and large end-users which is not currently found in Western Europe.

3.86 Another key development is that the level of US gas demand has recently fallen from a high point of some 23 tcf/a (around 640bcm) in the early 1970s to only 17-18 tcf/a (470-500bcm) in the period since 1983. This demand reduction of some 25% reflects a combination of increased energy conservation, reduced activity levels in energy-intensive industrial sectors and a lower level of gas use in power plants. It left the industry with considerable unutilised capacity in some major interstate transmission lines (though there is now demand for additional capacity in the north east) and put pressure on pipeline companies to move into third party transportation in an attempt to boost throughput. At the same time, reduced takes of gas by pipelines faced with falling demand led many producers to investigate ways of marketing the "gas bubble" of shut in production direct to end-users. In Western Europe, on the other hand, gas demand may have dipped in the early 1980s but has since recovered and is continuing to grow in most EC Members States, with the result that most major transmission lines are fully or almost fully utilised in periods of peak gas demand.

3.87 Another important consideration is the fact that the US is currently some 95% self-sufficient in natural gas. Imports from Canada account for almost all the other 5% of supplies, though very limited quantities of Algerian LNG are now imported via an east coast regasification terminal for peak-shaving purposes in the winter period. Although the US used to import relatively small quantities of gas by pipeline from Mexico, it has not done so in the last few years. By contrast, many EC Member States are highly dependent on imported gas supplies (and other imported fuels) and almost 30% of gas demand in the Community as a whole is met by non-OECD countries which might be regarded as politically less reliable. Thus the question of natural gas supply security generally looms much larger in Western Europe than it does in the US.

3.88 The concerns over supply security are an important example of significant differences in Government energy policy. Of similar importance is the degree of state involvement and ownership in the natural gas industry. Whereas gas companies in the US are generally privately owned, we have already noted the degree of state ownership in most transmission companies of Western Europe and the frequently municipal nature of many local distributors. Especially in the case of European gas transmission companies, the Government involvement often reflects an energy policy which, since the 1970s at least, has been geared towards the promotion of natural gas as a means of diversification away from oil fuels. In turn, it would be surprising if this high degree of Government ownership did not colour policy attitudes towards the market position, financial performance and future prospects of the transmission companies concerned.

3.89 The corollary of an essentially private gas industry in the US is a degree and complexity of regulation not known in Western Europe. Although some EC Member State Governments may seek to control or influence the level of gas prices to final consumers and (where relevant) the price at which gas is sold from the transmission company to local distributors, the transactions between transmission companies and the gas producers have (with a dew exceptions) been left to commercial negotiation. In the US, on the other hand, changes in the regulatory regime and court action have often had a much more direct influence over the way in which the natural gas industry has developed than Federal Government policy per se. As outlined in Appendix A to this report, the emergence of considerable third party transportation in the US since 1983 reflects efforts on the part of gas companies to take full advantage of a rigid and inflexible regulatory regime. Regulatory action to allow local distribution companies to "market out" of take-or-pay commitments to the pipelines at a time when regulated city gate prices had become significantly out of line with lower market realisations played a particularly crucial role in the whole process. The legal, administrative and regulatory aspects of the US situation are outlined in somewhat greater length in section IV of this report.

3.90 The fundamental conclusion suggested by these important difference in the gas supply situation as between the US and the EC is the fact that the development of common carriage in the US on a voluntary (not mandatory) basis reflected a very particular set of circumstances which stand in marked contrast to the situation in the Community. It would therefore be quite misleading to conclude that US experience can easily be transferred to the European context. Nor would it be appropriate to conclude that the US situation is in every way preferable. First, it is to be questioned whether common carriage on the present scale will survive the US gas "bubble" or ("sausage") of shut-in production and, as gas prices recover from their lowest levels, there are already some signs of a return to long-term contractual trading arrangements in place of 30 day "spot" business. Moreover, the regulatory regime in the US has introduced such distortions of company behaviour and resource allocation that the more market-oriented approach to gas trading generally followed in Western Europe is now regarded in some quarters, at least, as a "role model" for the United States gas industry. Although there may be lessons (both positive and negative) for the EC from the US experience, the kind of third party transportation which has emerged in the US cannot be regarded as a direct prescription for change in the EC gas market.

Implications for common carriage

3.91 Having examined relevant aspects of the gas supply situation in the European Community in some detail, as well as presenting a brief comparison with the US situation, it may be helpful at this stage to highlight some of the most important implications of our assessment for a possible common carriage system at the Community level. The most important pointers to the likely impact of such a common carriage system include the following:-

(a) the impact of common carriage might tend to be greater in Member States where the gas industry is not vertically integrated (across transmission and distribution) and where there is not a high degree of common ownership as between transmission and distribution companies;

(b) it is of crucial importance that many of the major European gas transmission lines are heavily utilised under conditions of seasonal peak gas demand, thus limiting the scope for carriage deals which would add to throughput. Nevertheless, carriage deals which would simply substitute transported gas for transmission company purchases or which were interruptible at times of peak demand might still be accommodated from a physical capacity point of view;

(c) many pure transmission companies have a cost structure in which gas purchases account for a very considerable proportion of total expenses. Even if a more competitive market were to lead to greater efficiency in non-gas expenditures, the total impact on gas selling prices would probably be rather limited. Vertically integrated utilities (such as GdF or British Gas) and distribution companies tend to have a much higher proportion of non-gas costs and thus greater scope for efficiency improvements but in the case of distribution companies, in particular, the competitive pressure which common carriage might conceivably introduce is unlikely to be as great as for transmission companies;

(d) there are some significant variations in gas selling prices to comparable distribution companies and large end-users, both within and between Member States. Within-country variations are most marked in countries such as the UK and West Germany, where prices are negotiated rather than resulting from published tariffs. As between Member States, price variations for large users tend to be more significant for firm gas than for interruptible sales. Some large buyers in the UK and West Germany, in particular, might consider that they could achieve lower prices for firm gas by making use of common carriage, while interruptible prices are sometimes relatively high in Belgium and France;

(e) it is important not to exaggerate the number of large consumers who might be both willing and able to take advantage of common carriage, in terms of their offtakes (level and reliability), system location, load factor and take-or-pay commitments which might conceivably be attractive to gas producers seeking to make a direct sale via common carriage. Only some of the very largest consumers would be in a position to negotiate purchases direct on their own behalf, though it is at least possible that a number of medium sized consumers could join together to do so, either through association (as with the UK Major Energy Users Council) or through an intermediate marketer/ broker as in the United States. The possible further development of natural gas consumption in power stations could significantly add to the potential for a common carriage system to be used, since the size and nature of the load would be well suited to a direct purchase. Nevertheless, it seem reasonable to suggest that some of both the proponents and detractors of a possible gas common carriage system in the Community have tended to exaggerate the extent to which such a system might actually be used, particularly in the short to medium term;

(f) on the supply side, it is vital to recognise that many European gas transmission companies have already committed themselves extensively to long-term gas purchase contracts, often with periodic price renegotiations but almost invariably with take-or-pay offtake commitments as well, which will cover a substantial portion of their projected sales through to 2000 and well beyond. It will therefore be important to return in section VI to the likely impact of common carriage on the purchasing utilities' take-or-pay positions; and

(g) finally, the US gas supply situation is markedly different from that prevailing in the European Community and it cannot be presumed that US experience with widespread use of third party transportation can be transferred readily to a European context.

IV THE CURRENT LEGISLATIVE, REGULATORY AND ADMINISTRATIVE SITUATION

Introduction

4.1 In this section, we examine the current legislative, regulatory and administrative situation in the Community as it affects natural gas. Two areas are of particular interest - the existing barriers to internal trade in natural gas and legislation in some Member States which provides for or addresses the possibility of common carriage. As required by the study Terms of Reference, we look in some detail at the UK situation because of its legislative provisions relating to third party use of the British Gas pipeline system. We then examine the situation in other Member States and at the overall Community level, in terms of the relevant articles in the Treaty of Rome, the powers of the European Commission and its administrative procedures as they apply to internal trade in natural gas. National legislation in the various Member States is discussed in an analytical rather than descriptive manner, since DG XVII has itself recently collected an inventory of the relevant laws and regulations, on the basis of which other consultants have prepared a summary of national legislative barriers to the free movement of gas in the Community. In order to assess any lessons (either positive or negative) from North American experience, we then examine briefly the very different legislative, regulatory and administrative system in force in the U.S.

The United Kingdom

4.2 As mentioned above, the existing UK legislation (1986 Gas Act) is of particular interest because it explicitly provides for the possibility of common carriage in the British Gas system and also established a regulatory body with powers to decide the terms of carriage if requested to do so by a third party seeking gas transportation. We therefore describe the overall legal framework in force, examine the common carriage aspects and then discuss the import/export regime for natural gas.

Legal Framework

4.3 The legislation which provided for the privatisation of BG was the 1986 Gas Act, which also put in place a new legislative and regulatory framework for gas supply in Great Britain. This was required following privatisation and the abolition (in the Oil & Gas Enterprise Act of 1982) of the monopoly which BGC had previously held (by virtue of the 1972 Gas Act) over the supply of gas through pipes. The 1986 Act gave the Secretary of State for Energy the power to authorise gas companies to supply gas within a specified area. Companies authorised under Section 7 of the Act are known as public gas suppliers and effectively have a statutory monopoly (and a corresponding supply obligation) in respect of supplies to premises within their authorised area which:

(a) use gas at a rate not exceeding 25,000 therms (69,000m^3) per year; and
(b) are within 25 yards (23 metres) of an existing distribution main belonging to the supplier.

No authorisation is required to supply gas at rates exceeding 2 million therms (5.6 mcm) per year, but potential competitors wishing to sell to customers taking less than this amount would need authorisation to do so. On 28 July 1986, British Gas was authorised to supply gas through pipes to any premises in Great Britain and is likely to be the only public gas supplier for the foreseeable future. This effectively means that they have a virtual monopoly of gas sales to tariff customers at rates of up to 25,000 therms but may face competition for supplies to larger customers.

4.4 As a public gas supplier, BG is obliged (under Section 14 of the Act) to sell to customers using not more than 25,000 therms pa on the basis of a non-discriminatory tariff. It may (but not obliged to) sell to larger customers under the terms of special agreements. Section 9 and 10 give BG a statutory obligation to supply tariff customers situated within 25 yards (23 metres) of an existing distribution main and a weaker obligation to supply other customers where it is reasonable and economic to do so.

4.5 The maximum price at which BG may sell to its tariff customers is governed by the terms of its Authorisation, condition 3, which contains a formula of the type "RPI-X+Y". Effectively, there are two elements to the regulatory formula. First, there is the average cost of BG's gas purchases in the relevant year (Y), which it is allowed to pass on entirely to the tariff customer. Second, there is a non-gas element which is allowed to increase each year at a rate equivalent to the increase in the retail price index (RPI) less two percentage points (X). There are procedures for the formula to be reviewed by the regulator at the end of an initial five year period which runs to 31 March 1992.

4.6 Prices for gas sold to contract customers (taking more than 25,000 therms pa) are not regulated under the Act nor the BG Authorisation, but BG is required (under condition 5 of the Authorisation) to publish maximum prices for contract sales. The maximum price for firm contract sales has typically been set a little below the commodity element of the tariff and, in its initial publication of maximum contract prices on 23 August 1986, BG also gave a heavily qualified undertaking to limit increases to around the rate of inflation. Contract sales are explicitly excluded from the provisions of the 1986 Gas Act precluding "undue discrimination" in pricing and supply, but BG's statement of August 1986 includes a weaker undertaking that BG "will not set prices so as to restrict, distort or prevent competition contrary to the public interest". The original decision not to regulate gas contract prices following BG privatisation reflected the presumption that, although there was not immediate competition from other gas suppliers, the industrial market competition from oil suppliers would be sufficient to ensure that BG could not exploit its position. Since November 1987, however, BG's industrial gas pricing policy has been under investigation by the Monopolies & Mergers Commission, following complaints from a number of industrial customers that BG was using its monopoly position in a manner contrary to the public interest. Reporting in October 1988, the Commission has now recommended an amendment to the BG Authorisation, which would require BG to operate non-discriminatory pricing and supply policies in the contract market. This would appear to imply a radical change in current BG policy, towards a series of published large user tariffs.

4.7 The Gas Act of 1986 created the post of Director General of Gas Supply in order to regulate the gas supply industry in general and the privatised BG in particular. James McKinnon was subsequently appointed as Director and currently heads the Office of Gas Supply (known as Ofgas). Among his duties are the protection of consumer interests, the promotion of efficiency and economy and a duty to "enable persons to compete effectively" in the gas contract market. The Director is responsible, among other things, for the regulation of the tariff market and for monitoring the operation of the regulatory pricing formula on maximum tariffs.

4.8 Since the gas contract market is not regulated, the Director does not have any specific powers in this respect. Instead, the contract market falls under general UK competition law, including the 1973 Fair Trading Act and the 1980 Competition Act, and the powers under that legislation of the Director General of Fair Trading. Customer complaints on BG's industrial gas pricing policy were made to the Office of Fair Trading (OFT) during 1987 and this led to the reference by the OFT to the Monopolies and Mergers Commission in November of that year. Just as the OFT has the power to refer matters to the MMC which relate to contract gas supplies, the Director General of Gas Supply may refer matters for MMC study which he considers an abuse of monopoly power in the tariff market, particularly if it appears they could be addressed by modification to the terms of the BG Authorisation.

Common Carriage Aspects

4.9 Under the 1986 Gas Act, the Director General of Gas Supply also has an important role in relation to possible third party use of the BG pipeline system. In this respect, the Act's provisions are significantly stronger than those of the 1982 Oil & Gas (Enterprise) Act. The 1982 Act first removed BG's statutory "right of first refusal" on the purchase of UKCS gas supplies and placed an obligation on BG to transport gas for third parties in return for a carriage charge. However, no third party use of the system actually occurred. A combination of several different factors may explain the apparent failure of the 1982 legislation to produce competition in gas supply, including:-

(a) the time lag involved in bringing new gas supplies on stream which are not already contracted or committed to BG. This is probably at least 2-3 years, even in the UK Southern Basin, reflecting the time required for project planning and design, construction, Government approval procedures and negotiations for transportation and sale;
(b) the downturn in oil prices from late 1985 onwards, which eroded potential profit margins on direct gas sales to industrial consumers via common carrier;
(c) the imprecision of the 1982 Act's provisions on carriage charges, which made it difficult for producers and end-consumers to assess the potential gains from common carriage and reinforced a certain reluctance to put at risk their relationship with BG;
(d) fear that BG might be able to discriminate in its gas purchasing policy against producers who tried to sell direct to consumers via common carriage;
(e) BG's ability to "out-bid" large consumers in gas purchase negotiations, as occurred when ICI sought to buy gas from the Hamilton-operated Esmond, Forbes and Gordon fields in 1982-83; and
(f) the ability of BG to conclude back-to-back purchase and sale agreements in substitution for gas carriage, as with the 1986 agreements for supplying some of Shell/Esso's Fulmar gas to their Mossmorran ethylene plant.

4.10 The 1986 Gas Act (Sections 19-22) gives the Director General of Gas Supply three sets of powers in relation to common carriage. These powers are exercisable in response to applications to him from third parties seeking common carriage in the BG system and entitle the Directors to:

(a) specify the terms on which gas should be carried;
(b) require BG to build additional capacity into new high-pressure pipelines to provide for common carriage; and
(c) require modifications to existing high-pressure pipelines (junctions or increased compression, for example) in order to provide capacity for common carriage.

In considering applications relating to common carriage, the Director is required to satisfy himself that this would not prejudice the transportation of gas required by BG to meet its own statutory or contractual supply obligations or, indeed, any common carriage arrangements which have already been put in place. As regards the terms of payment for providing transportation, the 1986 Act is more specific than the 1982 legislation but may still be open to different interpretations. Section 19, sub-section (5), contains the key provisions of the Act in this respect and refers to charges based on the "appropriate proportion" of pipeline system costs, plus the return which BG is earning on the capital value of its system.

4.11 The Director General of Gas Supply, James McKinnon, is taking his duty to enable contract market competition very seriously and has gone out of his way to encourage third party use of the BG system. Late in September 1988, the first application was made to him for directions in relation to carriage through the BG pipeline system and the Director has decided to give directions rather than instruct the parties to resume negotiations. These first directions will clearly be crucial for the future of common carriage in the UK. In the meantime, several other common carriage negotiations with BG are under way, but there is still no actual third party use of BG's system. Although the legislative framework is more conducive to common carriage now that it was under the 1982 Act, the depressed level of oil prices is still a factor hindering the development of competition to BG from other gas suppliers. Especially in the interruptible market, BG has had to reduce its own selling prices to compete with oil and the potential gains from a direct supply are often insufficient to make it worth producers and consumers putting at risk their existing relationships with BG.

4.12 During passage of the Gas Bill, in June 1986, BG gave to Parliament a "Residual Purchase Assurance" which was announced on their behalf by a member of the House of Lords. This was a statement to the effect that it would not discriminate against UKCS gas producers who offered to sell to BG gas that was surplus to the requirements of other customers supplied directly via common carriage. BG undertook to consider any such offers of gas on their merits. The force of the Assurance remains unclear and it has not dispelled concern among UKCS producers that direct sales would prejudice the development of other gas reserves for sale to BG. As part of its recommendations, the MMC report also proposed that BG should henceforth be able to contract for at most 90% of a gas field's reserves. Only if the producers were unable to find a buyer for the remaining 10% within a period of 2 years could BG then take up the remaining portion of the field. The aim of this recommendation is clearly to open the way for direct sales and overcome the problem that industrial gas buyers could probably not "underwrite" an entire field with take-or-pay commitments.

4.13 Under Condition 9 of its Authorisation, BG was required to prepare and have available on request a statement setting out guidance for persons wishing to have gas conveyed through its system. BG's statement (dated November 1986) indicates that carriage charges would reflect the input point and destination of the gas conveyed (and thus the elements - national transmission, regiional transmission or distribution grid - of its pipeline system which are used), the load factor of the supply, the volume carried and the duration of the carriage agreement. Two examples are given of carriage charges, at 3.5 and 4.0p/therm (around ECU $0.02/m^3$), but these reflect only the use of the transmission system, and not the distribution grid. For customers on the distribution system the carriage charge could be considerably higher than this - perhaps another 7.5 p/therm (ECU $0.04/m^3$) according to the recent MMC report. The Director General of Gas Supply has been careful to say that he has not endorsed BG's method nor its suggested charges and it would be open to him to set lower charges in response to the application which has been made to him.

4.14 A BG customer can be fairly confident of his supply security, because of the diversity of gas supply sources available to the company, whereas a direct supply from a single field might well be less reliable. This raises the question of back-up supplies from BG in the event that the direct gas supply to a consumer were interrupted due, for example, to production problems offshore. In this respect the 1986 legislation represents an advance on the 1982 Oil & Gas (Enterprise) Act. The BG Authorisation (condition 10) required BG to prepare and have available on request a statement for guidance on the supply of back-up gas to third parties. BG's statement, dated November 1986, is rather vague but envisages an initial payment for the right to back-up gas, a standing charge and a commodity charge for any back-up gas provided. As with the general statement on conveyance of gas for others, this has not been endorsed by the Director General of Gas Supply and no agreement for back-up gas has yet been concluded.

Import/Export Regime

4.15 In 1985, while British Gas was a nationalised industry, the UK Government decided not to endorse a draft contract negotiated by the Corporation for the purchase of gas from the Norwegian Sleipner field. Subsequently, the Secretary of State for Energy announced on 6 March 1986 that BG would in future be able to import gas, subject to the normal requirement for consent under the Petroleum and Submarine Pipelines Act 1975 for the laying of pipelines across the UKCS and, in the appropriate cases, the conclusion of inter-governmental treaties. In turn, BG gave an assurance to the Secretary of State that it would consult the Government about its import plans as these develop. Under the terms of UKCS production licences, all oil and gas from the UKCS has to be landed in the UK unless the Secretary of State consents to landing elsewhere. On 6 March 1986 the Secretary of State also announced that the Government was prepared to consider applications for waivers of this "landing requirement" for gas on a case-by-case basis. In doing this it would take into account considerations relating to the security of the UK's gas supplies without any presumption that exports should not take place.

4.16 Earlier this year, the Government appears to have raised no objection to BG's agreement with Algeria's Sonatrach for limited peak-shaving supplies of LNG over the next few winters. The relatively small scale of the deal, its contribution to the security of peak gas supplies and the fact that these imports present no real threat to the continued development of UKCS reserves were probably all factors in the relatively trouble-free passage obtained by BG for its proposals.

Other Member States

4.17 In view of the detail of legislative, regulatory and administrative situations already gathered by DG XVII itself and by other consultants on its behalf, our assessment of the position in other Member States set out below is a summary of the key features of relevance to the question of gas common carriage and a more open internal market in natural gas.

Belgium

4.18 The main legislative obstacle to the free movement of natural gas in Belgium is the exclusive concession for storage and transport by pipeline of natural gas given to Distrigaz by a law of 1983. As Distrigaz is sole concessionaire, it is effectively the only organisation with a right to physically import or export gas. In turn, the Control Committee for the gas and electricity industries, which involves Government, trades union and industry federation representatives as well as gas and electricity executives, has a broad mandate of control over the gas industry. It effectively acts as a watchdog body in relation to tariffs, gas supply, technical and financial matters, gas transportation, imports and exports. Moreover, the responsible Government Minister has a right to oppose any Distrigaz management decision which he considers contrary to the law, the relevant statutes or the public interest. From a strictly legal viewpoint, it is unclear whether there is any impediment to Distrigaz carrying gas within its own pipeline system on behalf of a third party. In practice, however, the Belgian Government and other Control Committee members appear to retain considerable influence over the way in which gas transportation and supply develops.

4.19 Gas distributors in Belgium are granted concessions to distribute by local authorities and are subject to local authority regulations on network development, as well as the statutes of local authority associations relating to technical and commercial conditions for gas distribution. The legal obligation on Distrigaz and the distributors to supply gas to consumers exists only in so far as it is technically and economically feasible to do so; this contrasts with an absolute supply obligation for some consumer categories in some other Member States, such as the United Kingdom.

France

4.20 The legal framework for gas transmission in France dates from a law of 1946 nationalising the gas and electricity industries. As amended, the law provides that only a public undertaking, or a national company in which the State or public undertakings have a majority holding, may transport gas to a distribution utility. This effectively limits gas transmission to organisations like Gaz de France, the Elf/GdF joint venture SNGSO and the Elf/GdF/Total owned CeFeM. In practice, SNGSO operates like an Elf subsidiary and manages its own transmission grid; the CeFeM grid is actually operated on its behalf by GdF. The 1946 law also gives GdF an absolute monopoly over the import and export of gas. Thus Norwegian gas produced by Elf Norge and destined for use by CeFeM has to pass into GdF ownership immediately prior to the French border, following which title returns to Elf. For this service, Elf pays a fee of 1% direct to GdF and a further 1% into a GdF employee benefits fund. Moreover, all agreements, including those relating to imports, exports or gas in transit, have to be submitted for approval to the Government Minister responsible for gas. The GdF import monopoly did not, however, prevent ElF from seeking (ultimately without success) to import Norwegian gas from the Sleipner/Troll fields for resale by CeFeM. Eventually, GdF signed the purchase contract but agreed to supply a proportion of the imported gas to CeFeM. There is no common carriage obligation in France, but GdF transports imported gas to CeFeM under voluntary agreements and appears likely to transport Norwegian gas across France on behalf of Spain's ENAGAS in the 1990s and beyond.

4.21 Public service concessions for gas distribution are granted for local distribution. Such concessions grant a local monopoly, in return for which the distributor accepts a supply obligation up to 47 kWh/hour or 1500 hours/a of supplies (equivalent to some 7,000 m^3/a or several times average annual household consumption) in respect of existing customers. New small customers only have to be supplied if it is economic to do so and there appears to be no legal (as opposed to contractual) obligation to supply large industrial users. In fact, GdF itself has progressively absorbed almost all the local concessions, apart from around 20 local authority and mixed enterprise distribution companies which between them account for only 2½% of French gas consumption. GdF is also responsible for almost all the gas distribution within the areas of south-west and central France where SNGSO and CeFeM respectively handle gas transmission and direct sales to large consumers. There are provisions in the statutes of GdF and in the local regulations affecting distribution which prohibit discrimination in pricing and supply as between customers in comparable circumstances.

Italy

4.22 The two major gas-producing provinces in Italy are the Po Valley and the Adriatic Sea area of the Italian continental shelf, of which the latter is growing in importance over time. In the Po Valley area, the state energy company ENI (of which AGIP and SNAM are both subsidiaries) has an absolute monopoly of gas exploration and production. ENI also has the sole legal right to the construction and operation of pipelines for the transport of natural gas in the Po Valley area. This is a long-standing law from the 1950s; it originally related to gas produced in the Po Valley and it is legally unclear whether this exclusive right also covers the transportation of other gas through the area. Offshore, the legal position is somewhat different. ENI does not have a monopoly of gas production but has full rights in respect of new exploration acreage over a limited initial period. In practice, AGIP accounts for the vast majority of offshore gas production, although Montedison, Petrofina, Elf, Total, Deutsche Shell and others also hold offshore licences. ENI also has a legal right of first refusal over domestic gas production and almost all the output is in fact sold to its subsidiary SNAM. Thus most of Italy's gas production is sold from one ENI subsidiary to another and somewhat unusual contractual provisions are understood to apply. Because of its considerable onshore storage, SNAM is contractually obliged to take all AGIP's production on a daily basis, regardless of quantity, which provides for considerable flexibility in offshore operations. Payments made by SNAM for this gas are thus an internal ENI transfer price and have recently been reported as around 80% of international border price levels. In practice, SNAM has not insisted that all indigenous gas be sold to it and some independent producers sell their gas direct into the market. This is particularly true of a Montedison/Elf/Petrofina joint venture who own their own small, indpendent transmission grid. There are, in fact, three ways in which direct sales are made:-

(a) deliveries from the independents into their own grid;
(b) sale to SNAM and re-purchase for deliveries from independent fields remote from the independent grid through the SNAM system to the Montedison/Elf/Petrofina grid; and
(c) deliveries on a tariffed basis through the SNAM system from independents' fields to their own sites (e.g. Montedison chemical plants) located on the SNAM grid.

The volumes supplied in this way are, however, relatively small and some independent producers (such as Deutsche Shell) appear not to have been interested in selling their gas other than to SNAM.

4.23 ENI does not have a legal monopoly of gas transmission outside the Po Valley area but has a virtual de facto monopoly. As mentioned above, there is a small, independent gas grid in the east central part of the country to which SNAM supplies "top up" gas if the grid is in gas deficit and from which SNAM buys gas when it is in surplus. This is of minor importance and SNAM accounts for some 97% of all gas supplied to Italian consumers. SNAM does not have a statutory import monopoly either, though again it is the sole gas importer in practice. As far as exports are concerned, the national market is given priority over indigenous gas production, which may not be exported without special Government authorisation or without first being offered to ENI. In two Italian regions (Trentino-Alto Adige and Sicily), the regional law provides for a limited right to third party transportation where the owner of gas deposits does not take up the gas pipeline concession but nevertheless requires gas transportation. In this case the pipeline owner would be obliged to carry the gas, within the constraints of available capacity, at a rate agreed between the parties or otherwise fixed by the municipal "Assessore" for Industry and Trade. Neither region has any gas reserves and these provisions have not actually been used; the precedent is therefore interesting but of no practical significance. There is at present no general obligation to transport gas for third parties.

4.24 SNAM itself supplies around 55% of Italy's gas sales direct to around 3,000 large industrial customers, while the other 45% is sold on to nearly 2,000 local distribution companies for on-sale to small customers. These are governed by national legislation (eg on safety matters) and by the terms of their local concessions. There appears to be no statutory supply obligation in Italy, though in practice gas suppliers would regard it as a duty to maintain supplies to existing customers.

Netherlands

4.25 Under the terms of the Groningen concession granted to NAM (a Shell/Esso joint venture), the latter is obliged to sell all the gas produced to Gasunie. This is of great practical importance since over half of all gas supplied in the Netherlands is still derived from the Groningen field, which accounts for an even higher proportion of remaining Dutch gas reserves. More generally, it is understood that all indigenous gas production destined for the national market has to be offered to Gasunie. Gasunie also has a "first offer" right over non-Groningen gas to be sold for export, in that gas must be sold to it if it can match the best offer made by any foreign buyer. In practice, Gasunie buys all Dutch gas on offer regardless of its source and accommodates new fields by reducing output from Groningen. This then gives Gasunie an effective monopoly over gas exports from the Netherlands. There is no statutory Gasunie monopoly over imports, transmission or exports and in principle imports by other companies are permitted. This has been illustrated recently by the proposed importation of some 2 bcm/a of Norwegian gas by electricity association SEP, an arrangement which would effectively by-pass Gasunie if approved by the Dutch Government. Since the power plants which would use this gas are to be sited very near to the Emden landing point for Norwegian gas, it is perhaps unlikely that this arrangement will necessitate common carriage through the Gasunie system. The Dutch Government is heavily involved in key gas industry decisions and the Minister of Economic Affairs has the legal power to approve both buying and selling prices for gas within the Netherlands. Although Gasunie has no legal monopoly of sales within the Netherlands, its "evergreen" rolling 15 year sales contract with VEGIN obliges the local gas distributors to purchase their entire requirements from Gasunie.

West Germany

4.26 The legal framework for natural gas supply in West Germany is rather less restrictive than in most other Member States. There are no legal restrictions on the right to transport gas, although in practice Ruhrgas in particular has a very strong position as owner or co-owner of most major transmission lines. The established transmission companies have also divided the country between them through a series of long-term (20 year) bilateral "demarcation agreements" (Demarkationsvertraege). These bilateral agreements cannot preclude competition from a third party, but in practice distribution utilities and large consumers have little real choice of gas supplier. Under the 1957 law against limitations to competition (Gesetz Gegen Wettbewerbsbeschraenkungen, or GWB), as last amended in 1980, those demaraction contracts concluded before 1980 and expressed to run for more than 20 years will automatically be terminated on 1st January 1995. There is no legal import monopoly and indeed electricity utilities EWE, RWE and VEW all have long-standing gas import contracts with Gasunie, in addition to imports made by gas utilities such as Ruhrgas, Thyssengas and BEB. Government approval is required for gas import contracts of over 2 years in duration, although in practice this appears to be something of a formality. In practice, however, it is difficult for new entrants to break into the gas market since they do not have a demarcated supply area; this was illustrated by the experience of BP subsidiary Gelsenberg, which was ultimately forced to sell the Norwegian (Statfjord) gas it had bought to Ruhrgas. Under the GWB (Article 103), the possibility of third party transportation is envisaged but there is no legal obligation to carry gas for third parties. Currently, Article 103 explicitly states that a system owner is entitled to refuse transportation (of gas or electricity) for a competitor. The West German Government now proposes to remove this provision; this would appear to make a refusal to carry subject to testing in the courts, but there would still be no obligation to transport and it is not clear that the practical impact of this change will be very great.

4.27 Distribution companies in West Germany are granted long term (20 year) local monopoly "concession contracts" (Konzessionsvertraege) by the municipality and in many cases they are actually part of the local authority public service arm ("Stadtwerke"). In practice, these concession contracts do not appear to be coterminus (except by coincidence) with the long term gas purchase agreements concluded between distributors and their transmission company suppliers. Nor are they coterminus with the transmission companies' demarcation contracts and the Government is now proposing (as an amendment to the GWB) that transmission companies should not be bound by any demarcation contract in respect of a distribution company whose existing purchase contract is ending and who might wish to change suppliers. There is a general obligation on gas utilities in West Germany to supply customers, regardless of size and location, unless it would be unreasonable on economic grounds to do so.

Others

4.28 There are also legislative constraints on the development of a more open internal gas market in the smaller gas-consuming Member States. In Denmark, Dansk Naturgas (Dangas) has the sole right to import, trade in, transport and store natural gas, under a law of 1972. Spain appears to have no legal monopoly as such, although national Government controls the concessions for gas trunklines and regional administrations are required to authorise local pipelines. BGE does not appear to have an exclusive legal right to transport gas in the Republic of Ireland, though in practice it is the sole transmission company. Government consent would be required for any gas exports, though for the time being the possibility of sales to Northern Ireland appears to have receded. The legal position in Luxembourg is unclear but SOTEG is in practice the sole gas importer. Even when there is no statutory monopoly over gas transmission, therefore, there are de facto monopolies which appear to have the tacit approval of the national Governments concerned.

The European Community

4.29 As the European Commission has emphasised in its working document COM(88) 238, internal trade in natural gas is subject to the general provisions of the Treaty of Rome. The working document also suggests that the Commission now recognises the need to apply these provisions more rigorously to the energy sector. This sub-section therefore looks at the powers which the Community has under the Treaty of Rome which could be used to implement a common carriage system in the gas sector. These are:-

(a) free movement of goods (Articles 30-37);
(b) competition (Articles 85,86 and 90);
(c) state aids (Articles 92-94);
(d) derogation from common carriage (Articles 8(a) & (c), Article 130(a) & (c)); and
(e) procedures for resolving disputes and complaints.

4.30 In the terms of competition policy within the Community, the gas sector has not as yet come under the scrutiny of the Commission. The rules regarding free movement of goods and competition have not yet been applied to this industry, so there is little in the way of a developed jurisprudence of Commission and Court of Justice decisions. This sub-section therefore looks at precedents and Community action in other sectors which may lay down generally applicable principles which may be relevant by analogy to gas common carriage. It addresses issues such as supply security and its relevance to free movement of goods; how the existing competition rules may be used to open up markets and force access to common carriage; questions of pricing; the position of state monopolies; whether there may be exemption from common carriage for the less developed regions and state aids. It also describes the procedures which may be used to resolve disputes and complaints.

Free Movement of Goods

4.31 As a product which is not specifically exempted from the scope of the EEC Treaty, gas is subject to the rules on free movement of goods (under Articles 30-36), as well as on free circulation throughout the Community (under Article 10(1)). The Commission working document COM(88) 238 on the Internal Energy Market emphasises that these rules should be enforced in the gas sector and also lists those measures which may be considered as an infringement of the free movement rules. Those measures which are of most relevance to the gas industry are:-

(a) rules which require mutuality for imports or exports;
(b) restrictions on the use of national utilities;
(c) pressure to purchase from national suppliers;
(d) certain price controls; and
(e) regulations which lay down technical requirements for a product.

4.32 Whether or not supply security in the gas sector would justify quantitative restrictions under Article 36 has not been directly tested. There is however a precedent in the oil sector in the Campus Oil case (case 72/83 (1984) ECR 272). The Court of Justice upheld, under Article 36, the right of a Member State (Ireland) to maintain in force legislation which required importers to purchase a certain amount of their requirements of petroleum products from a nationally based refinery on the grounds of public security even though such a measure had the effect of a quantitative restriction. The judgment sets a precedent for the recognition of public security in the energy sector. This might have implications for the gas industry if, for example, a national gas utility were alleged to be giving protection to indigenous gas production by obliging users to purchase a certain amount of that production even where imported gas is available at cheaper prices.

4.33 Monopolies, both state owned and private, are common in the gas sector throughout the Community. State monopolies are subject to the provisions of Article 37 of the EEC Treaty, whose primary purpose is to prevent discrimination regarding the conditions under which goods are procured and marketed between nationals of Member States. According to the circumstances, they may also be subject to the Rules on Competition (described in paragraphs 4.35 et seq below), by virtue of Article 90. Private monopolies are in any event subject to the general competition rules of the Treaty. Article 37 has so far been used in the energy sector mainly in relation to state oil monopolies in the new Member States. The Commission has pursued a policy of endeavouring to ensure that the new Member States take action to gradually dismantle their state monopolies in accordance with the provisions of the relevant Accession Treaties before the end of the transitional periods. It has forced the Spanish Government, for example, to introduce liberalising measures opening up the Campsa oil monopoly.

4.34 In future, however, the Commission could perhaps make use of its powers under the EEC Treaty in attacking exclusive rights of the state owned gas companies to import, export, transport or distribute natural gas.

Rules on Competition

4.35 How far the Rules on Competition contained in Articles 85-94 of the Treaty apply within the gas sector depends on whether the undertakings concerned with the supply of gas are involved in a cartel (in which case Article 85 may apply); are in a dominant position, which they abuse (in which case Article 86 will apply); are public undertakings (in which case Article 90 will apply and may mean that Articles 85 and 86 also apply); or receive State Aids (covered by Articles 92-94). (State Aids are discussed in paragraphs 4.46 et seq below). Working document COM(88) 238 confirms the Commission's intention to treat Articles 85 and 86 and Regulation 17/62 as applying to the gas sector. The document recalls the judgement of the Court of Justice in Case 45/85 to the effect that the Rules on Competition apply to all sectors of economic activity which are not expressly exempted and that Article 85(3) allows the characteristics of the sector to be taken into account without it being necessary to resort to a regulation under Article 87(2)C.

4.36 The fact that gas undertakings may be public undertakings, or undertakings to which exclusive or special rights are granted, does not necessarily remove them from the scope of the Rules on Competition: the test is whether the application of the Rules on Competition would obstruct the performance, in law or in fact, of the particular tasks assigned to the undertakings (Article 90(2)).

4.37 Where gas undertakings (whether they are State monopolies or not) fall within the scope of Article 90, the Rules on Competition can be enforced by means of a Commission Decision or Directive: the Commission can act without having recourse to the Council (Article 90(3)).

4.38 The Commission has used Article 90(3) in the Telecommunications sector when it adopted the directive on the liberalisation of the market for Telecommunications Terminal Equipment in order to force Member States to open up their markets to free competition and to dismantle the exclusive rights of the State monopolies. France has challenged the Commission's action before the Court of Justice. If the Court rules in the Commission's favour it will reinforce the Commission's power in this area.

4.39 The exception referred to in paragraph 4.36 above may apply to gas undertakings if, in the provision of services, they are under a statutory duty to carry out such tasks as the maintenance of secure supplies.

4.40 In the Sacchi Case (155/73 (1974) ECR), the Court of Justice interpreted this exception strictly in holding that, in order to qualify, undertakings must show that the application of the competition rules would be incompatible with the performance of their tasks. This may have implications for access to the pipeline by third parties.

4.41 If a gas utility refuses to transport third party gas, it may be in breach of Article 86. There is no legally binding precedent for saying that refusal to grant access is an abuse of a dominant position. DG IV did, however, issue an informal decision regarding the refusal to allow Texaco access to a kerosene distribution facility at Charles de Gaulle Airport in 1986 on the basis of a comfort letter, a procedure which does not create a legally binding precedent (see below). There have not been many complaints to DG IV on refusal to provide access. In the gas sector there has been only one complaint. This concerned Ruhrgas' refusal to allow Bayerngas to transport gas through its system which Bayerngas proposed to purchase in Algeria. Following price concessions from Ruhrgas, Bayerngas subsequently dropped its interest in gas transportation. Notwithstanding the resolution of the dispute between the parties, it is procedurally possible for the Commission to continue with its substantive case in order to set a precedent.

4.42 If a public gas pipeline owner were considered to be in breach of Article 86, the Commission could address a decision to it under Article 90(3) unless the Member State in question could prove that the case falls under the exception in Article 90(2). If the exception in Article 90(2) is invoked, it has to be proved that all requirements are met. It is unlikely that the transmission of third party gas would be an obstruction of the particular tasks assigned to the public gas utility under Article 90(2), so it is likely that Article 86 would be applicable.

4.43 If it appeared necessary to the Commission and Council to apply the Rules on Competition in a particular way to the gas sector, powers exist under Article 87(2)(c) of the EEC Treaty to define the scope of the Rules on Competition in that particular branch of the economy. Regulations or

Directives having this Article as their legal basis may be adopted by the Council, acting by qualified majority on a proposal from the Commission and after consulting the European Parliament. The use of this power is without prejudice to any other powers which the Commission and Council may have under, for example, Articles 100, 100A, 101 or 235 of the EEC Treaty.

4.44 Under the Rules on Competition, there are certain precise provisions governing pricing, in particular the direct or indirect fixing of purchase or selling prices by cartels and the direct or indirect imposition by undertakings enjoying a dominant position of unfair purchase or selling prices. Also, case law suggests that predatory pricing can fall under Article 86. In the Akzo Case of 1985 (Fifteenth Competition Report as point 82), the Commission held that action taken by Akzo Chemie in lowering prices in order to force a smaller competitor out of the market, was an infringement of Article 86. More generally, however, predatory pricing may be difficult to prove.

4.45 There is no cost-based rule setting out at what stage price undercutting becomes an abuse. Below-cost pricing may be judged in some circumstances to be an abuse and equally a dominant firm may not even have to sell below cost in order to force competitors from the market. The test is whether the price cutting constitutes unreasonable or unfair behaviour intended to eliminate or damage the particular competitor (Fifteenth Competition Report point 82).

State Aids

4.46 The working document emphasises the importance of enforcing the State Aid rules under Articles 92-94 in order to eliminate distortions of competition in the energy sector. The Commission intends to examine three categories of aid in the energy sector, including the use of energy tariffs as a means of giving aid to energy consumers, particularly in those sectors where energy costs are an important factor. There are, however, no cases where the Commission has had to apply the State aids rules to direct aid to the gas sector.

4.47 With regard to the use of energy tariffs as a means of subsidising energy consumers, there have been a number of decisions taken by the Commission, of which one is of particular interest to natural gas. In February 1988 the Court of Justice ruled in joined cases 67, 68 and 70/85 Kooy, Vliet, Landbouwschap and the Kingdom of the Netherlands V Commission (not yet reported), concerning preferential gas prices charged to domestic glasshouse horticulturists, that revenue which is forgone by the State through preferential treatment amounts to an aid.

4.48 The Commission has drawn up an inventory on State aid in the context of Internal Market White Paper. The information which it has gathered on aids existing in the energy sector will assist it in its assessment.

Temporary Derogation from Common Carriage

4.49 If the Commission decides to proceed with gas common carriage but considers a temporary derogation appropriate for "new" gas industries in Member States such as Spain, Portugal and Greece (see section VI), then it would have a legal basis for doing so under Article 8c. Article 130a and b may also provide a basis for giving a derogation from the common carriage system.

Procedures

4.50 An important related issued for the Commission is the extent to which existing procedures are adequate to "police" a common carriage system, particularly as regards the length of time required for a decision. In general, the remedies available in this area seem rather inadequate from the point of view of normal business practice, primarily because of the limited action available to aggrieved parties and because of the length of time which available procedures take. We consider in turn the procedures relating to the free movement of goods and to competition matters.

4.51 Matters concerning free movement of goods may in many cases be dealt with directly in the national courts, which may refer questions of interpretation to the Court of Justice under Article 177 of the EEC Treaty.

Action may also be taken by the Commission, first by way of reasoned opinion and secondly by way of reference to the Court of Justice under Article 169 of the EEC Treaty. Article 177 references themselves may take up to 18 months from the date of reference by the national court until the preliminary ruling is delivered by the Court of Justice. It must also be taken into account that it is only the court of final authority in a Member State which is under a duty to refer to the Court of Justice. Thus litigants may have to appeal cases through the national courts before the point may be interpreted by the Court of Justice, with all the delays which different Member State judicial systems may involve. Although there are no specific provisions for sanctions for non-compliance with the rulings of the Court of Justice, it may be possible to enforce the ruling in the national courts. Also, although Article 169 proceedings may only be taken by the Commission, it is open to other parties to lodge a complaint with the Commission which may lead to the Commission initiating proceedings.

4.52 The disadvantage of the procedures in competition matters from the point of view of business practice is again the length of time which it takes for a formal decision to issue from the Commission following a complaint (usually over two years). While the majority of competition cases dealt with by the Commission are settled without a formal decision, there may be a problem insofar as third parties are concerned. Because informal decisions taken by the Commission are not legally enforceable and as such have only persuasive authority in the national courts, there is a lack of legal certainty in such cases.

4.53 The problem could perhaps be resolved by the Commission dealing with complaints referred to it in this area on a formal basis in order to build up a body of jurisprudence and then introduce a block exemption regulation which could perhaps also apply to other energy or public service sectors.

<u>United States</u>

4.54 In Section III of the report, the very significant differences in the US gas supply situation from that prevailing in the European Community were identified and discussed. The legislative, regulatory and administrative framework for natural gas industry activities is also markedly dissimilar from that prevailing in Western Europe. Federal legislation such as the

1978 Natural Gas Policy Act (NGPA) has been of considerable significance, while both the regulatory authorities and the courts have played a much more important role in the United States than their European counterparts. Regulators control each level of the natural gas market, although the wellhead prices of some 50% of total US gas production have now been deregulated. There is a basic division of labour between the Federal Energy Regulatory Commission (FERC), which is responsible for regulating the wellhead prices of "old" gas as well as the transportation and sale of gas by interstate pipelines, and the various State regulatory commissions which regulate intrastate pipeline trade and local distribution companies. As the regulatory agency responsible for interstate pipelines, FERC has played a major role in the emergence of open access gas transportation.

4.55 Federal regulation of interstate pipelines in the US dates right back to the Natural Gas Act of 1938. A Supreme Court decision of 1954 then reinterpreted the Act in such a way as to extend Federal regulatory control to wellhead prices for natural gas sold into the interstate market. At this time, gas sold into the intrastate pipeline system remained unregulated. However, regulated wellhead prices failed to keep up with the rising cost of developing new, higher cost gas reserves and this contributed to the emergence of gas shortages and curtailment of deliveries to customers through the interstate system by the winter of 1976-77. This situation, together with forecasts of future gas scarcity, led to the passage of the NGPA and the Powerplant and Industrial Fuel Use Act (FUA). The NGA extended wellhead price controls to "old" gas sold in the intrastate market, whilst at the same time allowing for phased partial wellhead price decontrol of new and high-cost gas production. This legislation - with some parallels to the 1975 European Council directive on the use of natural gas in power stations - also restricted the use of gas by large industrial users and power utilities, though many waivers of FUA restrictions were subsequently given in the changed market situation of the 1980s.

4.56 FERC regulation of prices for sales from pipeline companies to local distributors has operated on a historic average cost basis, allowing pipelines to add certain permissible costs and a specified rate of return to their average system supply cost of gas purchases. This system, coupled with the very low regulated wellhead prices of "old" gas and the partial decontrol of other wellhead prices introduced by the NGPA, encouraged pipeline companies to respond to perceived gas shortages by paying above-market prices for new and high cost gas and "rolling in" these high prices to achieve an average cost acceptable to their citygate customers. Many of the contracts made between pipelines and producers over the period 1978-82 included non-market-responsive price terms (such as indexation with general price inflation, regardless of alternative fuel prices). This contributed very significantly towards the problems which emerged as demand began to turn down in the early 1980s, due to a fall in oil prices, difficult economic conditions and accelerated energy conservation. As explained in Appendix A, many pipelines actually shut-in low price "old" gas supplies in order to minimise the take-or-pay cost under their gas purchase contracts. This gave rise to the well known "bubble" of shut-in gas production.

4.57 In the new market situation which arose from 1982, the weaknesses in a non-market-responsive, regulated system were exposed as producers sought customers for low priced shut-in gas and local distributors sought transportation services from pipelines so that they could buy lower-priced gas direct from sources independent of the pipelines. A short-term "spot" market in gas began to emerge, associated with the growing use of third party transportation in interstate pipelines. Following court action which ruled against the discriminatory terms of some transportation services provided to third parties by pipeline companies, FERC issued its Order 436 in 1985. This provided interstate pipeline companies with blanket authority to transport third party gas on a non-discriminatory basis. It was intended to provide consumers with greater access to competitively priced gas but participation by pipeline companies in the Order 436 programme is voluntary. Thus there is no mandatory obligation on pipelines to carry gas for others. Once they opt into the programme, however, they may not refuse to provide transportation as long as they have the requisite pipeline capacity. Moreover, the service must be provided on a non-discriminatory basis. In practice, this means that in the event of restricted throughput capacity, third party volumes shipped under transportation arrangement are cut back on the basis of "first come, first served" priorities among third party shippers. Gas transported on an "interruptible" basis at lower rates (usually on behalf of industrial and power plant end-users, rather than distributors) may be cut back and, where rates differ between shippers, those shippers paying the lowest transportation rate will receive the lowest priority. Following the introduction of Order 436, the proportion of interstate pipeline gas being moved under transportation deals rather than conventional purchase and sale arrangements rose to around half by the end of 1986, as against just 3% in 1982.

4.58 In 1986, FERC moved to relax control over "old" gas wellhead prices, through its Order 451. Instead of a previously complex system of different regulated prices for different "vintages" of old gas, Order 451 created a single new ceiling price for old gas of around $2.50 per 1000 cubic feet, subject to monthly adjustment, below which producers and purchasers are free to negotiate a contract price between themselves. This programme therefore created greater incentives for producers to develop incremental output from old gas fields and to sell this additional gas at commercially more attractive prices.

4.59 To European observers, the US gas industry may appear something of a paradox. Essentially privately owned, its development has been extensively shaped by the action of legislators, courts and (especially) regulators. In particular, the development of third party transportation on a voluntary basis has its roots not only in recent regulatory action to introduce more market-orientated behaviout in conditions of surplus, but also in the market imbalances created in large part by the rigidities and lack of market responsiveness in the regulated trading environment of perceived gas shortage in the late 1970s and early 1980s. The regulatory system in the US is extremely complex and we have only been able to outline its key features in this brief review. Nevertheless, it is absolutely crucial to be aware of the enormous differences between this system and the situation in the gas industry of the European Community, especially as regards the arguments for and against the introduction of a common carrier system in Europe.

Summary of Key Issues

4.60 As with previous sections of the report, it may be helpful to summarise briefly the key conclusions of this section as regards the specific issue of common carriage in natural gas. A number of points are of particular importance, including the following:-

(a) de facto monopolies over gas transmission are almost universal within the Member States of the European Community and these are reinforced by de jure monopolies of one sort or another in countries such as Belgium, Denmark, France and Italy;

(b) comprehensive common carriage legislation only exists in the UK and the practical impact of this legislation has yet to be tested, although it is understood that a carriage negotiation has now been referred to the regulator for a ruling;

(c) administratively as well as legally, many national Governments retain a substantial measure of control over the development of the natural gas industry in Member States, so that the attitude and policy response of Governments could have an important influence on the impact of a possible common carriage system in the Community as a whole;

(d) the European Commission already possesses a number of general powers under the Treaty of Rome which it could apply more rigorously to the natural gas sector in order to "police" a common carriage system, though there might well be a case for a Council directive containing more specific guidelines and a streamlining of procedures for resolving complaints and disputes; and

(e) the role of regulatory agencies and the courts in the development of the US natural gas industry has been more significant than it has in EC Member States and this is an important factor to bear in mind when considering the degree of third party gas transportation which takes place in the US.

Before reaching any definitive conclusions in respect of (c) and (d) above, in particular, it is necessary to consider in considerably more detail the kind of common carriage regime which might be desirable, practicable and effective at the European Community level. We therefore turn to an examination of this issue in Section V of the report.

V CONDITIONS FOR EFFECTIVE COMMON CARRIAGE

Introduction

5.1 Before moving in Section VI to a detailed assessment of the advantages and drawbacks of a gas common carriage system at the Community level, it is important to examine precisely what kind of system might be envisaged and the conditions which would have to be fulfilled in order for it to be effective. UK experience under the Oil & Gas (Enterprise) Act from 1982-86 suggests that the legal possibility of common carriage may exist for a considerable period without actual third party use of pipeline systems taking place. Even under the more conducive provisions of the 1986 Gas Act in the UK, it is likely that competition to British Gas will take some years to emerge and the recommendations of the recent Monopolies & Mergers Commission Inquiry effectively recognise that further intervention is required to promote direct producer-consumer sales by common carriage. Although third party gas transportation emerged very rapidly in the United States, this took place under conditions which were very different from those prevailing in the European gas market. This therefore suggests that careful consideration needs to be given to the conditions under which a common carriage system in the Community could be made effective. If these conditions are not fulfilled and third party transportation is not effectively promoted, then the impact of a common carriage system would be negligible and the question of advantages and drawbacks becomes redundant.

5.2 Key issues which need to be addressed in connection with the possible introduction of a common carriage system at the Community level include:

- (a) the nature of the legal obligation (if any) to carry gas for third parties;
- (b) the level and structure of carriage charges to be paid by third parties for transportation;
- (c) the approach to pipeline capacity constraints and the provision of new pipeline capacity;
- (d) ways of ensuring that competition within the new environment is not distorted by state aids, predatory pricing or by discriminatory,

collusive or other anti-competitive practices on the part of gas industry players;

(e) the removal of barriers to free competition in natural gas created by statutory monpolies, exclusive rights, statutory restrictions and restrictive commercial agreements; and

(f) the development of an appropriate institutional framework for the regulation and supervision of a more open and competitive gas industry.

Each of these key issues is addressed in turn below.

Obligations to transport

5.3 An absolutely fundamental question is the nature of the obligations which might be placed on pipeline owners to provide transportation and related services for third parties. In the US, commercial incentives to engage in third party transportation were such that no legal obligation was required for common carriage to develop. As Appendix A points out, blanket transportation Order 436 was voluntary and yet most of the interstate pipeline companies opted into the scheme. In the light of the very different circumstances prevailing in the European gas market, it is unlikely that this voluntary approach would be very effective in the Community. Careful consideration therefore needs to be given to the overall framework of carriage obligations.

5.4 It is important to be clear at the outset of this discussion that common carriage might mean some sort of obligation on owners of pipelines and related facilities to provide a range of services, of which long-distance gas transportation is simply the most important. In practice, the services which a transmission company could conceivably be required to provide include:-

(a) "firm" (year round) third party gas transportation;

(b) "interruptible" transportation, under which the pipeline owner can interrupt the third party carriage arrangement at times of peak gas demand on the system;

(c) a "load factor" service, converting a high annual load factor supply from the producer to a lower load factor supply which meets the consumer's requirements;

(d) a "modulation service", converting a regular supply from the producer to meet any fluctuations (over the day or over a longer period) in the consumer's gas offtake;

(e) a "back-up" service, protecting the consumer against any shortfall or interruption in the producer's supply or (conceivably) covering the producer against plant downtime or other failures to take on the part of the consumer; and

(f) adjustment of gas quality to meet the requirements of customers' appliances.

5.5 Transmission companies currently use a combination of their pipeline systems, storage facilities and multiple gas supply sources to provide these services to their own customers and many of their suppliers. These often allow producers to make the best use of their production and transportation equipment by supplying regular volumes at high load factor, whilst at the same time meeting the varying needs of gas consumers for flexible, secure supplies at reasonable cost. For third party transportation to take place, both producer and end-consumer must see advantages in direct marketing. Given that consumers often have requirements which go beyond gas volumes (supply security, flexibility, gas quality etc), there is a need to address the possible provision by transmission companies for third parties of all the services referred to above.

5.6 A number of different contexts may be envisaged in which transportation and related services might be provided for third parties, including:

(a) gas in transit through the country (or supply area) concerned, ultimately destined for sale in another utility's market;

(b) gas being marketed directly to a new customer in the pipeline owner's own supply area;

(c) gas being marketed directly to an existing customer in the pipeline owner's own supply area, with gas originating from the same producer as with the previous purchase and sale arrangements; or

(d) gas being marketed directly to an existing customer in the pipeline owner's own supply area, with gas originating from a different producer than before.

5.7 Particular problems are likely to be encountered where the provision of services to a third party by the transmission company concerned may conflict with the provision of similar services to the company's own remaining customers. Arrangements relating purely to transit - such as Norwegian gas passing through the Netherlands to Belgium and France, or across France to Spain - may not raise any such conflicts, especially if it is recognised that a new pipeline is required for the specific purpose. In contrast, direct marketing to large, new customers (such as a new gas-fired power plant) in the pipeline owner's own supply area may well place demands on the transmission company which exceed its existing capacity to meet them. Turning to existing customers who may seek to buy direct, the distinction between (c) and (d) above may in practice be blurred since particular supply sources are rarely identified with particular customers and in some cases the source of gas supplied to an existing customer may vary according to the time of year, for example. In principle, however, it is possible to conceive of a proposed direct purchase by an existing customer which does not add to the services which were previously "bundled" into the sale of gas at the plant or city gate. On the other hand, an existing customer might seek to buy direct from a new or different source in such a way that that would strain the transportation and related storage capacity of the pipeline system owner.

5.8 It is important to recognise that transmission companies will have a number of firm contractual commitments to their existing customers - to provide certain volumes of gas of an acceptable quality and in most cases to provide a certain amount of delivery capacity or offtake flexibility as well. Some companies also have statutory obligations of one kind or another to meet their customers' requirements, as discussed in Section IV above. These contractual and/or statutory commitments involve supplies to many household and other consumers who, in the short to medium term, have no real alternative to the use of gas and who would not themselves be in a position to purchase gas direct from producers. Even where there is no specific long-term statutory or contractual commitment to supply, domestic users and others quite reasonably expect that gas will be made available to fuel their central heating and other appliances over the entire life of the equipment. For social welfare reasons as well as on legal or contractual business grounds, it would be most unreasonable if new direct marketing arrangements via common carriage were to pre-empt capacity required to meet already existing commitments to supply other users. Apparently, there are some precedents internationally for common carriage systems which permit new users access to already full pipeline systems and cut back existing users' throughput rights pro rata in order to facilitate this arrangement. Some oil pipeline transportation in the United States is understood to operate in this way and some objections which have been raised to the idea of gas common carriage in Europe appear to rest on fears that similar principles would apply in this case. For the reasons explained above, however, we consider that this would be quite unreasonable in the context of the European gas supply situation. Instead, any obligation to provide transportation and related services to third parties should normally be subject to the availability of sufficient capacity to provide these services, without prejudice to other supply obligations already existing at the time. The question of providing further system capacity to meet the demand for additional services is discussed below.

Carriage charges

5.9 As regards carriage charges themselves, it is possible to envisage two extremes in terms of the type of common carriage system which might be introduced. At one extreme, the European Commission might simply announce that commercial negotiation of transportation arrangements is encouraged and that it (or some agency acting on its behalf) will act as arbiter of disputes. It might then use its powers under the Treaty of Rome (primarily Article 86 on abuse of dominant position) in the event that one party or another considers that good-faith negotiations are not taking place. At the other extreme, the Commission could actually seek to set tariffs at which gas should be carried by pipeline owners for third parties. There are many objections to the latter, not least the sheer complexity of the gas transportation system in Europe (including different costs of transmission in different parts of the system) and the dangers evident from US experience of inflexible over-regulation. Moreover, the Commission has tended, wherever possible, to allow competition to flourish on a commercial basis established between willing parties, providing this is not injurious to the public interest. A single tariff, or even a single set of tariffs, would almost certainly be inappropriate in many contexts, lead to a number of objections or anomalies and run the risk of the Commission becoming embroiled in detailed and protracted disputes. These arguments therefore militate against any attempt to try and specify ex-ante precisely what the tariff should be in any particular circumstance.

5.10 Nevertheless, it must be recognised that many producers and consumers (apart, perhaps, from new power station gas users) seeking to make use of common carriage would be putting at risk a long-established relationship with a gas transmission company. They would naturally seek to compare the commercial terms of their existing arrangements with those which they could expect from direct marketing. Given the risks attached to an innovative form of trading, they may only pursue the common carriage option if the commercial prospects appear to be clearly superior to those of continued sale and purchase dealings with the transmission company. If no ex-ante guidelines or principles are established for what constitutes a "reasonable" carriage charge, then there is a danger that producers and consumers will not take the risk of exploring the common carriage option, since they would have no basis on which to judge in advance whether it would be worth their while to do so. In this event, the common carriage system introduced is unlikely to be very effective. It is sometimes suggested that a contributory factor to the lack of common carriage response to the UK Oil & Gas (Enterprise) Act of 1982 was the absence of any guidelines on carriage charges and, in this respect, the 1986 Gas Act was an improvement but still not altogether clear in its meaning. If, moreover, the Commission is to act in some sense as the arbiter of disputes - and some protection against abuse of monopoly positions will no doubt be needed to make common carriage effective - then it would seem sensible to set out some guidelines or principles for resolving such disputes before the first negotiation breaks down and is referred to Brussels. Some consideration therefore needs to be given to the type of guidelines or principles which the Commission might set down.

5.11 The key issues to be considered in relation to charging principles include:

(a) whether charges should be based on average or on marginal cost;
(b) whether transportation charges should distinguish between different levels of system cost;
(c) whether transportation charges should be distance related;
(d) the distinction between firm and interruptible carriage charges;
(e) charges for other services such as storage and "back up"; and
(f) "ship-or-pay" ("use-or-pay") provisions.

Merely raising these issues does not necessarily mean that we believe the Commission would need to make a definitive policy statement on each of them. In the UK, for example, the legislation on carriage charges is rather general and BG itself was required to make statements of charging policy which could then be considered by the regulator. Nevertheless, a policy of seeking to "rule by exception" (only intervening in commercial negotiations when an apparent abuse of monopoly position had taken place) would still require the Commission to have reached a view on what it regards as reasonable commercial behaviour. We therefore consider briefly each of the key charging issues in turn.

5.12 The argument on average versus marginal costs turns largely on the stage of development of the transmission grid and related facilities, including the degree of capacity utilisation. Average costs are simply the total unit cost of constructing and operating a pipeline; there is often a problem of defining the unit capital cost for existing lines (historic cost versus full replacement cost depreciation), but in concept the average cost approach is fairly straightforward. Marginal cost is rather more complex. Where transportation requires new capacity, the marginal cost is relatively high; for pipelines with spare capacity, however, the (short run) marginal cost of moving additional gas volumes may be very low, reflecting only the compression and other variable costs of gas transmission. Before examining the specific issue of charges for common carriage, it may be helpful to consider how transmission companies currently behave in relation to their own customers. At least in respect of firm gas sales, any transmission company which is still expanding its grid or which is operating at or near full capacity utilisation will generally seek to recover the full cost of its facilities, plus a return on capital. If it did not do so, it would be unlikely to generate the cash required to finance the construction of the replacement and additional capacity it requires. For a short period, perhaps, such a company might be prepared to cover only its (short run) marginal operating costs of supply to some customers, for whom it needs to reduce selling prices in order to remain competitive in times of low oil prices, for example. The longer term overall objective would, however, generally be to recover average cost plus a profit. On the other hand, a transmission company which has essentially completed its pipeline grid, or which faces lower than expected throughputs and thus spare capacity, might well be prepared to make more sales which at least cover (short-run) marginal but not average costs, in order to achieve greater utilisation of its system and contribute towards fixed costs. Some US pipelines are currently in this position and there are perhaps one or two European examples as well; the Netherlands appears unlikely to need any very significant expansion of its pipeline network and the Belgian grid was planned to accommodate a higher level of throughput and sales than those currently being achieved. Nevertheless, the vast majority of Member States will need to expand their networks to some degree at least and it therefore seems reasonable to assume that firm gas is generally sold at prices which, taken as a whole, cover average costs plus a profit.

5.13 We turn now to the specific question of carriage charges. Leaving the possibility of interruptible transportation aside for the present, our view is that it may not be sensible to oblige transmission companies to provide common carriage at the short run marginal, or incremental, cost of that specific service. If, on the other hand, the pipeline owner is prepared to offer marginal cost transportation for commercial reasons, then there could surely be no objection. The main argument against a marginal cost carriage obligation is that, in order to finance continued grid development, the transmission company might then seek to over-recover on average costs for its remaining customers. These customers would generally include smaller and less powerful gas consumers who could not themselves take direct advantage of a common carriage system. If the transmission company were unable to increase prices for other users in this way - because of regulation, for example, or competition from other fuels - then its capacity to finance future grid development or even to service existing debt might well be impaired.

5.14 One argument in favour of obliging pipeline system owners to provide services at marginal cost is that selling prices to some of their own large customers may not fully recover average costs. If the transmission company can sell at prices which reflect only marginal costs to its own large customers and is entitled to levy carriage charges on the basis of average cost plus a reasonable return, then this may give the transmission company an unfair competitive advantage over gas producers seeking to sell direct into its market area. The transmission company might only need to do this for a short period to head off the threat of competition, following which it could increase its price again. Although this appears to us to be a logical argument, there are several comments which can be made in regard to it:

(a) gas utilities may need to sell to their own customers at marginal cost prices at some periods in order to compete with other fuels and it would be anti-competitive to curtail their freedom to do so;

(b) marginal cost sales pricing to a limited number of consumers could probably be regarded as discriminatory, but it is not predatory in the sense that the avoidable costs are recovered;

(c) it is, in practice, difficult to assess whether pipeline owners are covering marginal or average system costs for their own gas sales, since the relevant cost information is generally not available and the extent of joint costs in the gas industry makes it difficult to allocate system costs as between different types of customer; and

(d) marginal cost carriage charges could vary enormously, depending on the state of capacity utilisation in a particular part of pipeline system and the need (if any) for uprating investments, such as extra compression, to accommodate the third party gas. This could then appear to give anomalous or discriminatory results.

5.15 Ultimately, the average versus marginal costs argument comes down to assessing a balance of risks, from the point of view of achieving an effective common carriage system without undue damage to other objectives such as equity and continued gas supply security. An obligation to provide services for third parties at (short run) marginal cost could have adverse consequences for other gas consumers and for the future development of the grid, while an entitlement to charge average cost could in certain circumstances give the pipeline owners' own sales a competitive edge over direct marketing by producers. On the balance of the arguments, our own view is that it would not be sensible to oblige gas utilities to provide firm transportation (or other services entailing year-round or peak period capacity) at marginal cost.

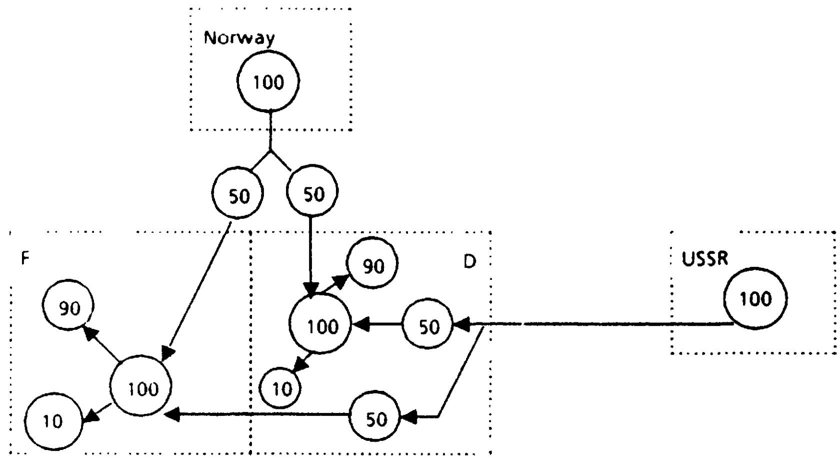
5.16 If we assume for the present an average cost charging principle - pipeline owners being permitted to recover at most their average costs plus a reasonable profit - an important practical question is then the distinction between different levels of system cost. The point here is that the cost of providing transportation for third party gas will vary very greatly as between different parts of a pipeline system. One reason for this is that the unit capital cost of a pipeline tends to increase much less than in proportion to the capacity of the pipe. Moreover, higher operating pressure in parts of the system mean great throughputs and lower unit costs. While it would be undesirable for pipeline owners to discriminate unduly between third party shippers requiring similar services from similar parts of the system, it does appear to make sense for the owners to distinguish between different "layers" of the grid. British Gas, for example, are understood to base proposed carriage charges on a "three tier" approach to their system; in order of increasing unit carriage cost, these are national transmission (high pressure), regional transmission (medium pressure) and distribution system (low pressure). In gas industries which are not vertically integrated, transmission and distribution systems are under separate ownership, but the general principle appears a sound one. Thus a direct marketer selling to a customer located on the high pressure transmission system should expect to pay a lower transportation charge (other things being equal) than for an arrangement involving lower pressure deliveries from a different "tier" of the system.

5.17 The issue of distance related carriage charges is linked to the possibility of re-optimising gas flows within the integrated European gas grid, following a decision to market gas direct via common carriage. This may perhaps best be illustrated by some extremely simplified numerical examples, as set out in Figure 5a overleaf. We assume that there is, initially, no common carriage and that gas demand of 100 units in each of France and West Germany is supplied equally from Norway and the Soviet Union. In each consuming country, 90 units are sold to small domestic/ commercial users and 10 are sold to large industry. We also assume for the sake of simplicity that each pipeline has 10 units of spare capacity. Suppose now that a new industrial user in West Germany requires an additional 10 units of gas, but decides to buy direct from the Soviet Union. The result is straightforward (Case A in Figure 5a) in that gas is transported through the West German pipeline system along the "notional

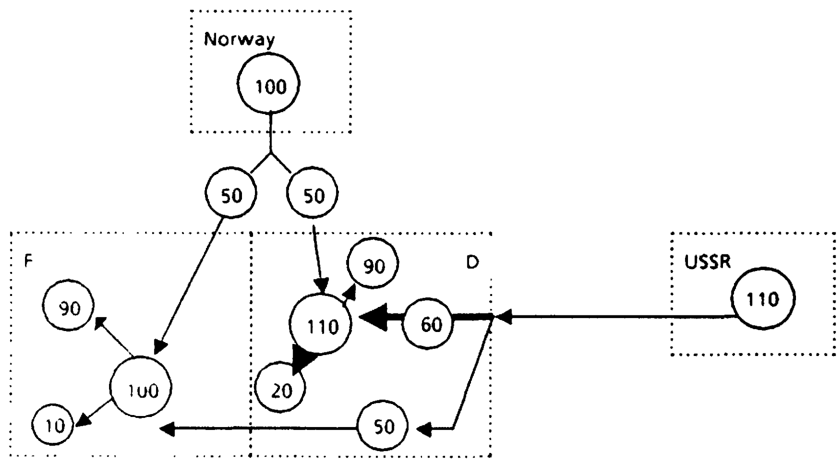
Figure 5a

DISTANCE-RELATED CARRIAGE CHARGES:
Simplified illustrative examples

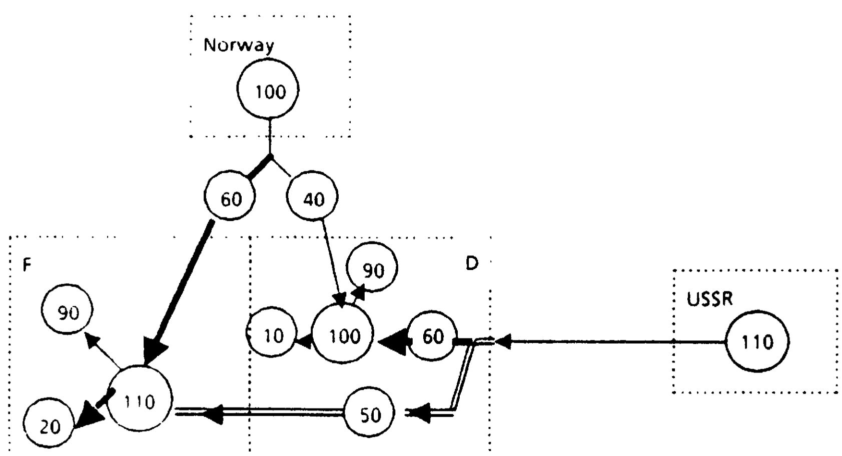
Base case (no common carriage)



Case A (direct marketing, USSR to FRG)



Case B (direct marketing, USSR to France)



path" marked in bold. In such a case, it is reasonable to assume that the carriage charge might be related in some way to the distance along the notional path.

5.18 Suppose, however, that the new industrial demand for gas to be carried from the USSR arises in France, rather than West Germany. This is shown in Figure 5a as Case B. In this case, the industrial consumer would probably negotiate with French and West German pipeline owners for carriage over the notional path shown as a double line. However, the pipeline owners may then be able to agree between them to an arrangement which would reoptimise flows and reduce their transmission costs. If pipeline capacities permit and the distances involved are shorter, the West German transmission company might agree to a gas "swap" whereby it would receive an additional 10 units of Soviet gas, in exchange for which the French would accept 10 units of Norwegian gas contracted for sale to West Germany. Thus the amount of Soviet gas physically transported to France would be unchanged. In this case, additional volumes of gas are carried along the routes marked in bold and less gas moves from Norway to West Germany; the additional cost of the carriage arrangement thus bears little relation to the "notional path" and charges related to distances along the "notional path" might well over-recover the cost of carriage. This is clearly a simplified example for purposes of illustration. In practice, some new investment will almost certainly be required, but the gas swap arrangement might require provision of less new capacity than would transportation along the "notional path". Currently, the transmission companies' policy is to build "notional path" capacity for supply security reasons, even where a swap will normally take place (eg for Soviet gas bought by BEB and Thyssengas). Thus only limited operating cost savings are made. In future, a buyer of direct supplies via common carriage might be prepared to take a greater supply security risk and dispense with the "notional path" capacity as a fallback. This could then permit a greater saving in transmission costs. Whether this would be acceptable to the gas producers and transmission companies involved is, however, open to doubt.

5.19 Thus an argument could, in principle, be made for a detailed, case-by-case, investigation of incremental carriage costs (taking account of any gas flow reoptimisation which takes place), rather than relating charges to distances along the notional path along which the third party gas might initially be assumed to travel. There are a number of comments which can be made on this point:

(a) "swap" deals to reoptimise gas flows might not be practicable in some cases, owing to limited spare capacity on other pipelines;

(b) it is notoriously difficult to "trace molecules" of physical gas flow through a complex pipeline system, especially when deliveries from certain producers and to some classes of customers vary considerably as between different times of the year;

(c) gas swaps are the subject of commercially confidential deals between transmission companies and their terms could not easily form the basis of carriage negotiations with producers or consumers;

(d) charges based on distances along the "notional path" for gas carried may, on occasion, lead to some over-recovery of costs by pipeline owners, but do at least have the great advantage of simplicity and transparency; and

(e) even if carriage charges could practicably take account of any reoptimisation of flows, such a charging system could remove or at least diminish the commercial incentives which transmission companies currently have to make swap deals and thus reduce costs.

5.20 On balance, therefore, we would favour a system of carriage charges which is relatively simple and transparent. Transparency is important since both producers and consumers should ideally be able to evaluate the likely commercial benefits of a carriage arrangement, as compared to sale and purchase of the conventional kind. A reasonable charging system might therefore be based on the distance along the most direct "notional path" between the point of entry to the pipeline owner's system and the point of delivery to the consumer, taking account (as argued above) of the "tiers" in the pipeline system used by the third party gas. It is worth noting that this system could perhaps begin to erode existing non-discriminatory tariff systems which set similar prices for all comparable large consumers, irrespective of their geographical location on the transmission grid. With common carriage, favourably located users would have the opportunity to secure relatively low gas supply costs.

5.21 A further element in the structure of charges for third party gas transportation is load factor and the distinction between <u>firm and interruptible carriage</u>. As far as firm transportation is concerned, it is reasonable for the pipeline owner to charge higher rates (in ECU/m^3/km, for example) for gas transported at lower load factors. This is because a large proportion of gas transportation costs are capacity costs; operating costs (compressor fuel, labour and other running costs) are relatively minor in comparison. Since a lower load factor reduces throughput for a given pipeline capacity, unit capacity costs can be significantly increased. Turning to interruptible carriage (transportation interruptible on an agreed basis at the pipeline owner's option when capacity is required to meet seasonal, year round demands), this does not appear to be specifically addressed in the UK legislation but does take place to a significant extent in the US. Clearly, this service is more appropriate for direct marketing to large industrial or power plant customers with a standby fuel than it would be for direct sales to local distributors or to firm gas customers. The idea would be that some consumers could take advantage of seasonal spare capacity in some transmission pipelines which carry lower load factor supplies (such as Dutch gas exports to West Germany or Belgium, for example). By definition, interruptible carriage in pipelines which are not fully utilised outside the winter peak does not impose any capacity cost on the pipeline owner and it would be reasonable to expect carriage charges to reflect this. Depending on the contractual freedom of the transporter to interrupt, it appears that interruptible carriage ought to be much cheaper (in ECU/m^3/km) than firm transportation and a "fair" charge might be nearer to (short run) marginal than to average costs in this case.

5.22 The foregoing discussion relates mainly to charging for transportation itself, but it may be equally important for the effectiveness of a common carriage system to ensure fair and reasonable charges for <u>other services</u> outlined earlier in this section, including storage, back-up and gas processing or blending to meet quality requirements. Although the distance-related and system levels concepts are not relevant to facilities other than pipelines, the "average cost plus normal return" principle could still be applied. In the case of storage or blending plant, a relatively high proportion of the cost to third parties is likely to be the charge for reserving capacity. "Back-up" gas is a somewhat complex issue, since this could conceivably be provided either out of storage or in some cases by using offtake flexibility in the transmission company's own gas purchase contracts. If a consumer who is purchasing gas directly via common carriage requires year round back-up against a shortfall in the direct supply, then this may prove rather expensive since the means of providing back-up to a third party are often of considerable value to the transmission company for meeting its own customers' peak winter demands. Much may depend on the utility's peak match (peak supply capacity versus projected severe winter firm gas demand) and the period over which back-up is required. It would be most unusual for a utility to have a considerable projected surplus at peak for many years ahead, which might allow back-up to be provided relatively cheaply. Large industrial or power plant users with a standby fuel option therefore have a further advantage in terms of ability to buy direct, since they may be able to accept carriage without an expensive back-up provision.

5.23 Transmission utilities providing transportation and related services may well wish to secure "ship-or-pay" ("use-or-pay") commitments from the shipper. This means that the shipper would agree in advance to pay for services relating to at least a specific volume of gas, whether or not he actually uses the pipeline system and other facilities to that extent. In the US, FERC does not appear to have permitted ship-or-pay terms for transportation under Order 436, but this may reflect the degree of under-utilised capacity in the interstate system. Within the Community, there is a much greater likelihood that some additional capacity will need to be provided to meet third parties' requirements and in such cases ship-or-pay appears entirely reasonable. Even where new capacity is not provided, there will frequently be some opportunity cost to the pipeline owner of committing some spare capacity to a third party - such as loss of system flexibility, supply security or the chance to sell that capacity to another third party. In consequence, it appears to us that ship-or-pay could well constitute part of a fair and reasonable package of terms for common carriage.

Transmission Capacity

5.24 As we have argued throughout this report, a good deal of the European gas pipeline and storage facilities are heavily utilised and the extent of any spare capacity is very considerably less than in the United States. In some instances, such as interruptible carriage or a decision by an existing customer to buy direct from the producer whose gas he has been burning already, it may be possible to meet third parties' requirements from existing system capacity. Nevertheless there will undoubtedly be many situations in which capacity uprating (such as extra compression) or completely new capacity would be required in order to accommodate proposed direct marketing arrangements. One possibility might be for the third party to construct and operate new pipelines or other facilities itself, though in some Member States there are currently legal restrictions on the right to import or transport natural gas which might prevent this. Another option is some sort of joint venture with the transmission company already operating in the area and considerable volumes of gas already move across European borders on the basis of joint ventures between gas utilities. A third possibility is to develop some system for incorporating third party requirements when the grid is updated or expanded.

5.25 In order to facilitate the incorporation of third party requirements into grid development, some form of notice procedure may be appropriate. Gas utilities planning to construct new pipelines or upgrade the capacity of existing lines (in each case, those above a certain pipe diameter or operating pressure) could be obliged to register their plans well in advance with the Commission, or some other body acting on its behalf, and to publish them officially. Third parties would then be free to identify any known capacity requirements of their own for gas transmission along the published routes and, where physically and environmentally practicable, the responsible gas utility could then be obliged to incorporate the extra capacity required in their project. Payment by the third party could conceivably take the form of a direct contribution to capital costs (including a reasonable return for the pipeline owner) in return for subsequent dedicated throughput rights, or else a prior commitment to ship-or-pay quantities at an agreed tariff once the new facilities are in operation. Similar provisions to this already exist in the UK Gas Act of 1986, articles 20-21, where a two year notice period applies unless otherwise specified by the Director of Ofgas. Whereas, in relation to carriage charges, the Commission might choose to "regulate by exception" (intervene only where a breach of competition law is alleged to have taken place), the institution of this system in the Community would require a definite initiative from the Commission. The approach would probably need to allow for short notice construction of pipelines in exceptional circumstances, in order to meet previously unanticipated consumer demands.

5.26 A further issue to be considered is the possibility of restrictions of pipeline capacity and interruptions to, or shortfalls in, gas supply which might affect consumers who were buying gas direct via common carriage. This raises questions of priorities, both as between the pipeline owner and third party shippers on the one hand, and among a number of different third party shippers on the other. To an extent, such matters could be left to commercial agreement between the parties involved; the main concern that the European Commission might have is to ensure that pipeline operators do not abuse their position by applying priority rules in an arbitrary or discriminatory manner. The application of some kind of "first come, first served" priority system (as in the US) would appear to be a reasonable step, though the US also has some precedents for establishing priorities among interruptible carriage arrangements on the basis of the transportation rates paid. Since this is an extremely complex area in which the procedures may need to be tailored to particular circumstances, it would probably be unwise for the Commission to seek to do more than establish general guidelines or principles of what would be regarded as acceptable behaviour under the Treaty of Rome (Article 86).

Fair Competition

5.27 One of the chief purposes of introducing some form of common carriage system for natural gas transportation within the Community would be to promote a greater degree of competition among gas suppliers - among Community gas producers, between these producers and non-Community suppliers, among gas transmission companies and between established transmission companies and new, direct marketing arrangements. Perhaps of crucial importance is the competition between transmission companies' merchanting activities and direct sales from producers to consumers via common carriage. In all these areas, it will be important to ensure that "fair" competition takes place and we have already raised some of the key concerns in the course of this section. There are a number of other areas which need to be considered, including:

(a) the possible availability of subsidies or "state aids" to existing gas utilities;
(b) selective "predatory" price discounts to preserve market position against the threat of competition; and
(c) collusive, discriminatory or other anti-competitive behaviour on the part of market players.

Matters such as this would fall under the European Commission's general powers to enforce fair competition under the Treaty of Rome; it may, however, be helpful to highlight some potential problems at this stage.

5.28 Earlier this decade, both Gaz de France and SNAM were placed under some political pressure by their respective Governments to conclude gas purchase contracts at above-market prices with Algeria. As part of these arrangements, direct Government subsidies were provided to the two utilities for a limited period. Much criticised in some quarters at the time, these subsidies came to an end several years ago and contract prices were brought more into line with market netback realisations. At the time of writing, none of the major gas transmission companies appears to receive any direct subsidy of this sort. However, the Danish gas industry obtains a considerable indirect subsidy in that it sells to small users and district heating plants at prices related to tax-inclusive oil prices. There is no tax on natural gas in Denmark, while taxes on gas oil and fuel oil are around 130% and 220% respectively; thus the utilities effectively get to keep the tax revenue which the Government loses when gas is substituted for oil. This arrangement thus releases funds which the industry can use for further investment is expansion of the gas grid and storage facilities. Denmark is certainly not the only Member State which taxes oil products more heavily than gas; it is perhaps the most dramatic example, although Italian rates of duty on gas oil are also extremely high. Such instances reflect deliberate Government intervention through the tax system to promote the substitution of natural gas for imported oil. It should, however, be noted that indirect subsidies of this sort do not constitute a "state aid" under the terms of the Treaty of Rome.

5.29 In the event that a common carriage system were introduced, there is at least a possibility that direct subsidies might re-emerge or that indirect subsidies resulting from high oil taxation in non-industrial markets could be used to cross-subsidise selling prices for gas in the industrial market, in order to fend off competition from direct marketing by gas producers. It is also worth noting that state-owned companies are responsible for all gas exports from Algeria and the Soviet Union, as well as a substantial proportion of Norwegian gas sales. There is therefore the possibility that their marketing efforts could be supported directly or indirectly by the Government in those countries. Under common carriage, even more than at present, it would be important to ensure that subsidies provided to producers or to gas utilities did not distort the pattern of competition and trade.

5.30 Predatory pricing is in some ways a similar issue. One concern is that gas utilities should not be able to make selective discounts below cost in order to drive off the threat of competition from direct marketing. In those Member States with transparent tariff sales of gas to large users, such selective discounting is unlikely to take place, but it would be more feasible where prices are individually negotiated or adjusted from the published tariff level. In principle, it is predatory to price below avoidable costs; pricing below full average cost (including fixed costs) but above avoidable cost should generally be regarded as legitimate, especially over short periods, and is common for off-peak electricity sales as well as for interruptible gas sales. The definition and "policing" of predatory pricing in the gas industry is, however, particularly difficult, given the extent of joint costs (both gas and non-gas) across different market sectors. There is, for example, no internationally recognised convention on the allocation of system capacity costs as between firm and interruptible customers. However, it is not just transmission companies which might be tempted to price in a predatory manner. There is also the possibility that producing countries might be tempted to "dump" limited volumes of gas through direct sales at prices below costs, in order to gain market share. Dumping would be extremely difficult to prove and in any case gas production costs are probably still some way below selling prices in most producing countries. It has, however, been reported that the current selling price of Norwegian gas at Emden does not cover the transportation tariff through the Statpipe/Norpipe system for those sellers who do not have a stake in the line. Predatory pricing may be facilitated by a subsidy or state aid; it may, however, simply reflect a pure commercial judgement that a temporary loss position is justified by long-term competitive advantage gained as a result. Whichever is the case, it would be important for the European Commission to recognise the danger it presents to fair competition and to develop a view of what constitutes a "fair" selling price for gas in relation to the cost of supply.

5.31 A number of other threats to fair competition may also be envisaged. For reasons which we have examined above, there may be legitimate reasons why a pipeline company with spare system capacity cannot offer third party transportation - including supply security and commitment to meet projected peak demand from existing firm customers. There may, however, be a need to ensure that access to the pipeline, storage and gas processing system is not unreasonably refused and that pipeline owners do not collude to refuse transit transportation in order to protect one another's markets. As with some of the other fair competition issues raised in this sub-section, the role of the European Commission in this matter would be to respond to any complaints alleging abuse of dominant position. There are, however, important issues of supply security and capacity reservation for the foreseeable demands of existing customers which must be addressed in order to establish whether a stated inability to transport third party is genuine or not.

Monopolies and exclusive rights

5.32 There are in the European gas industry a number of statutory monopolies, exclusive rights and preferential treatments which appear inconsistent with the principle of free cirulcation of natural gas within the Community, particularly if a common carriage system were to be established. Failure to address these would leave a situation of uneven, partial and unfair competition in the gas industry, given the favourable legal treatment of certain enterprises in certain Member States. A number of examples were identified and discussed in Section IV and they include:

(a) exclusive rights to import, transport or export natural gas (such as the Gaz de France import monopoly, the Distrigaz monopoly of gas transmission and similar exclusive rights held by Dangas);
(b) exclusive rights to install and operate distribution grids and to sell gas to small consumers within a local area - these are usually given by a municipality and are common in most Member States where the gas industry is not vertically integrated;
(c) preferential "rights of first refusal" over the purchase of indigenous gas, such as those granted to Gasunie in the Netherlands and SNAM in Italy. (British Gas in the United Kingdom had such a right until 1982, when this was abolished); and
(d) restrictions on trade between Member States in natural gas, such as the UK "landing requirement" which, although it could be waived by the Government, still means that UK producers would need specific permission to export their gas.

As part of any move to introduce common carriage, it would therefore be important for the Commission to tackle these legal restrictions on internal trade in natural gas.

5.33 There is an important issue to be decided in respect of the application of common carriage to gas pipeline systems. One approach would be to open up transmission pipelines to common carriage but to retain local monopolies over distribution grids. In our view, this would be arbitary and discriminatory, since the division of customers as between transmission and distribution companies is very different in the various Member States. Some distribution companies supply only fairly small users, while those in Denmark supply all customers except power stations. Problems are also raised by the existence of vertically integrated gas companies operating both transmision and distribution grids and in the UK the common carriage regime makes no distinction between the two. Our view is that the physical installation and operation of a distribution grid is a natural monopoly, but the construction and operation of transmission grids does not necessarily require an exclusive right at the national level, as the West German experience illustrates. There is no convincing reason why gas <u>sales</u> should be a monopoly at either level, at least in a "mature" gas industry. We therefore consider that the Commission should address local exclusive rights to use the distribution system as well as exclusive rights to import and transport. In political terms, Commission initiatives in these areas will inevitably mean a reduction in the sovereignty of certain Member States over matters of energy policy as it relates to the gas sector. This raises important questions regarding the balance in policy-making authority as between Brussels and the national Governments.

5.34 There are also a number of contractual arrangements which, although not part of the legal framework, effectively give rise to a degree of exclusivity and which might arguably be considered restrictive . For example, the association of Dutch gas distributors VEGIN is understood to be contractually bound under a long-term "evergreen" agreement with Gasunie to purchase all its gas requirements from the transmission company. In West Germany, there is no legal monopoly over imports or transmission but the Demarkationsvertraege (Demarcation Contracts) concluded bilaterally between transmission companies have the effect of dividing the national market up into regional supply areas. They are not strictly exclusive, in that bilateral agreements cannot preclude competition by a third party, but do in practice give rise to de facto regional monopolies. The European Commission would therefore need to form a view as to whether such arrangements are compatible with a free internal market in natural gas.

5.35 The 1975 European Council Directive on the use of gas in power stations could also be considered a restriction of a kind on the free internal market. Formulated in a time of perceived gas shortage and rising oil and gas prices, there are convincing reasons to believe that it is no longer appropriate in an era of abundant gas reserves, low oil and gas prices, efficient gas combined cycle technology for generating power and growing concern for the environmental impact of other forms of electricity generation.

Institutional issues

5.36 In this section, we have discussed a number of important issues relating to the regulation of a common carriage system. While the Commission has received only one complaint to date regarding access to gas pipeline systems, this way well be because consumers consider they have too much to lose by complaining in the present environment. Large users can ill afford to damage relationships with their existing gas suppliers unless there is an expectation of ultimate advantage and this expectation may not exist at present, since there is no common carriage system in place and the cost of constructing entirely new lines would normally be prohibitive for any but the very largest or most favourably located of gas consumers. We therefore consider that the introduction of a common carriage regime is likely to bring with it a very significant increase in the number of complaints which the Commission receives. This underlines the importance for the Commission, not only of establishing a clear approach to the principles underlying the establishment and regulation of a common carriage system, but also of ensuring that it is institutionally prepared for the extra workload of regulating a complex industry.

5.37 The US experience of unwieldy over-regulation and a FERC of some 1,500 employees is not an example which we believe Europe should follow, but from 1986 the UK has recognised that a small, specific, gas industry regulatory body is required to administer a more open market. It would seem appropriate, therefore, for the Commission to consider whether its existing institutions possess the resources, expertise and experience of the gas sector to carry out this role. In our view, it may be necessary to consider a separate body with delegated powers and an ability to short-circuit some of the more time-consuming Commission procedures in order to reach decisions in a timely manner appropriate to the industry. There may also be some scope for delegating regulatory control to the individual Member States, though this would create some danger of regulation being applied inconsistently, with adverse consequences for the free and fair circulation of natural gas within the Community.

Recommendations

5.38 In Section VI of this report, we shall address the advantages and drawbacks of a possible gas common carriage system. If the European Commission, in due course, reaches the conclusion that there are net benefits to be had from such a system, then it is vital that the system introduced should be both effective and, as far as possible, fair. It is also most important that the complexities raised by developing and "policing" such a system should not be underestimated. Within the scope of this study, we have only been able to highlight some of the key issues, but our discussion and analysis does suggest the following tentative recommendations for further consideration by the Commission:-

(a) in order to promote open access and third party gas transportation in the Community, some form of (qualified) obligation to provide transportation and related services should be considered;
(b) any such obligation should be made subject to the availability of sufficient spare capacity (or additional capacity which could be made available readily and at low investment cost by the transmission company concerned), over and above that required to provide secure supplies to existing or remaining customers, taking into account any reasonably foreseeable increase in their demand for gas;
(c) existing statutory monopolies to import or transport gas appear to be incompatible with open access to the gas grid and would logically need to be dismantled if an effective common carriage system were desired. The physical construction and operation of gas distribution networks is a natural monopoly and exclusive rights to "dig up the roads" should be preserved, but this monopoly should not preclude the possibility of direct sales to customers on the distribution grid, via common carriage;

(d) even if the Commission wishes to "police" the common carriage system "by exception" (eg. to intervene only in response to complaints that dominant positions are being abused), it should nevertheless consider providing guidelines on what it considers to be reasonable and fair, in the interests of clarity and transparency;

(e) for example, the Commission could stipulate that tariffs for a "firm" (year round service) should not exceed the system owner's average cost (including fixed capacity costs) for the type of facility concerned (high pressure transmission line or storage facility etc), including a reasonable return in line with that normally earned by the utility concerned;

(f) charges for services interruptible at the option of the pipeline owner should not, however, include capacity costs unless they can be shown to impose such a cost on the system;

(g) charges for common carriage could then be left to commercial negotiation, within these guidelines, so that pipeline owners wishing to provide services at lower cost would be free to do so;

(h) the Commission should consider a procedure for publishing utilities' system development proposals, in order to allow the incorporation of third party capacity requirements, where practicable, at the cost of the third party concerned;

(i) the Commission should develop a policy position in respect of unfair competitive practices, including definition of predatory pricing or unreasonable refusal to carry third party gas, in order to permit a clear response to any complaints which might be addressed to it in this regard; and

(j) the Commission should also consider whether its existing institutions, gas industry expertise and resources are adequate to "police" effectively a system which will raise a number of complex issues and may well leave to more complaints being referred to it for resolution. In particular, the Commission may wish to consider the option of setting up a dedicated, separate body with delegated powers but responsible to and reporting to the Commission itself.

VI ADVANTAGES AND DRAWBACKS OF COMMON CARRIAGE

Introduction

6.1 Having assessed the energy policy, gas market and legislative environment into which a common carriage system might be introduced, together with the sort of system which would be required to promote a more open internal gas market, we now turn to the advantages and drawbacks of common carriage. For the purposes of this discussion, we assume that the system would be an effective one (at least in the long run) and we examine in turn the likely impact of common carriage on:-

(a) gas consumers - small users, large industrial consumers and power plants;
(b) the gas industry in the Community - transmission companies, distributors and Community gas producers; and
(c) the interests of the European Community as a whole.

6.2 It is important at the outset of this discussion to distinguish between effects of common carriage which would simply involve a redistribution of income within the Community and those which would generate additional benefits for the Community as a whole. Some of the impact of a common carriage system might be to transfer income or profits as between:-

(a) different gas industry organisations (eg between transmission companies and indigenous gas producers or between transmission companies and distributors);
(b) different consumers or classes of consumers; or
(c) gas suppliers and consumers.

To the extent that economic rents are merely reallocated without changing the total resource cost of gas supply in the Community, the impact must be carefully assessed but the benefit to the Community as a whole would not be substantial.

6.3 Real benefits to the Community as a whole rely on some identifiable reduction in the economic resource cost of energy supply. This could conceivably come about through:-

(a) a reduction in the real resource cost of gas production within the Community as a result of greater competition and increased efficiency or perhaps a geographical restructuring of production towards lower cost areas;
(b) a reduction in the cost (border price) of gas imported into the Community from non-EC producing countries;
(c) a reduction in the non-gas resource costs of gas supply, again as a result of increased efficiency or a rationalisation of industry activities promoted by common carriage; or
(d) a substitution of natural gas for other more costly forms of energy supply which might not be expected to take place without common carriage.

The benefits which might ensue would thus be a combination of what economists call "X efficiency" improvements (given organisations providing the same result at lower resource cost than they did before) and resource allocation improvements resulting from improved pricing signals and a rationalisation of activity in the direction of the more efficient operators in the sector. Our list of effects set out above focuses on the possible benefits to the Community; arguments could be and have been made that the impact will be in the opposite direction and it is therefore necessary to give consideration to the balance of probability and the likely net benefit in each case.

6.4 Even if it can be demonstrated that common carriage is likely to lead to significant positive net benefits to the Community as a whole, it will nevertheless be important to establish:

(a) a clear assessment of the likely 'winners' and 'losers' from common carriage and the nature and extent of the gains or losses; and
(b) a realistic appraisal of any increased risks (in terms of supply security or vulnerability to external energy market "shocks") that might be entailed by a common carriage system at the Community level.

6.5 Having identified the key issues, we now examine the likely impact of an effective common carriage system on consumers and the gas industry, followed by an assessment of the advantages and drawbacks for the Community as a whole.

Impact on gas consumers

6.6 As mentioned above, we consider in this sub-section the impact on three main categories of gas consumers - small users, large industrial consumers and power plants. First, we look at the impact on household gas consumers and other small users.

Small consumers

6.7 As suggested in Section III above, it is almost inconceivable that individual households or other small consumers would be in a position to take direct advantage of a common carriage system. It is therefore to be presumed that small consumers will, in general, continue to be provided with gas by their existing supplier, be it a local distributor or (in some cases) the integrated national gas company. The impact of common carriage on small consumers would therefore depend largely on:-

(a) the extent to which their suppliers are affected by common carriage; and
(b) the extent to which those suppliers pass on any net costs or benefits to their customers.

6.8 Perhaps the first point to be made here is that, in some Member States, the possibility of small consumers' existing gas suppliers taking advantage of a common carriage system does not arise. In both France and the United Kingdom, there is a vertically integrated gas company responsible for transmission and distribution, with the exception of the SNGSO and CeFeM supply areas in France. Ireland is also experiencing increasing integration of BGE into the municipal distribution end of the business. Effectively, therefore, the supplier of gas to small consumers must be taken as given.

6.9 In other Member States, there is in principle the possibility that local distributors could buy direct from producers, as has happened to some extent in the United States. For reasons which we examine in the sub-section dealing with the impact on distribution companies below, it appears unlikely that many would be both willing to do so and also in a position to obtain gas on more favourable terms than at present. If this conclusion holds, then the direct impact on small gas consumers of a common carriage system would be slight.

6.10 It could, however, be argued that even if the use of common carriage is largely confined to major industrial users or gas-using power stations, the introduction of new competitive pressures into the gas market could lead to a general reduction in costs, to the benefit of all consumers including smaller users. This is a complex question to which we will return below; in our view, the key cost element is the price of gas purchased from producing countries and there is considerable uncertainty as to whether the introduction of additional buyers would force a <u>general</u> reduction in gas purchase costs. The current "buyers' market" conditions for gas supplies into the Community provide a favourable environment, but the market also looks set to remain an oligopoly and this makes the outcome much more uncertain. Perhaps the most important point as regards small users is that, even if a general reduction in costs could be achieved, it would probably require a more competitive situation in residential and commercial energy markets to ensure that the benefits were passed on fully to small gas consumers. Our assessment is therefore that even the indirect benefits to small users of gas common carriage system are both highly uncertain and probably rather limited.

6.11 There could, in fact, be a number of ways in which small gas consumers could be adversely affected by common carriage. If, for example, pipeline owners were obliged to provide services at marginal (or variable) cost to large end-users who currently buy gas at prices which reflect full average cost (including fixed costs), then they could well seek to recover a higher proportion of fixed costs in prices to distribution companies and thus to small users. A similar effect could result if the loss of large consumers to direct marketing leads transmission companies to incur take-or-pay penalties which would then have to be recovered from the remaining customers. In the longer term, competing fuel prices would probably place some limit on the extent to which costs would be passed on to the residential/commercial markets in this way, but in the short term there would be little market (as opposed to political) resistance to such moves.

6.12 There remains one further aspect which should, perhaps, be considered. If it could be demonstrated that a gas common carriage system would allow the efficient use of natural gas in combined cycle power stations to flourish in a way which would not be likely without it, thus allowing power to be generated at reduced cost, then there might be considerable indirect benefits of gas common carriage for households and other small electricity consumers, as well as for large users of power. The likely impact of a gas common carriage system on the power sector is addressed in a separate sub-section below. In brief, our view is that if the increased use of gas in power stations is economically and commercially attractive then, in the present circumstances of abundant gas reserves and relatively slow projected growth in "mature" gas markets, it would not generally require common carriage to make it happen. Nevertheless, the favourable position of power generators as potential direct buyers of gas via common carriage would undoubtedly contribute downward pressure on the price of gas to power stations if a carriage alternative were available to them. There are already some signs of this in the UK, where would-be gas-fired power generators are considering the direct supply option as well as purchases from BG. Even if power plants did not actually purchase direct via common carriage, our view is that the mere existence of a gas common carriage option would probably be of benefit to electricity consumers in those Member States where gas use in power stations is likely to increase. We therefore consider that household energy consumers may perhaps be more likely to benefit from a gas common carriage system in their role as electricity purchasers, rather than as users of gas itself.

6.13 In summary, there is clearly an important distinction to be made here between large and small gas consumers. A number of large users (though even here it is probably a minority) are strong advocates of common carriage and believe that they would benefit significantly from it. The "burden of proof" in this regard appears to lie mainly with those who oppose common carriage to demonstrate why increased competition should not be permitted. In marked contrast, many millions of small gas users are in effect bystanders in the sphere of common carriage and in this case the burden of proof would appear to lie with the large consumer proponents of common carriage to demonstrate that there would also be significant benefits to small users. There may be a separate argument which turns on the macro-economic benefits to society of lower industrial gas costs, but we consider that there is no convincing case for the argument that small gas consumers would derive significant direct benefits from a common carriage system.

Industrial consumers

6.14 The position as regards large industrial consumers is rather different and a number would undoubtedly be keen to try and buy gas direct from the producers. For the foreseeable future, however, direct interest in common carriage is likely to be confined to a relatively small number of very large users, many but not all of whom are in the chemical industry. Not surprisingly, the most likely direct buyers are found in highly energy-intensive sectors where relative gas costs are an important element of their overall competitive position in international markets. Moreover, the large gas consumers found in the chemicals and (to a lesser extent) steel industries often have the high volume, high load factor gas offtakes which would given them a reasonable prospect of negotiating attractive direct purchase terms. Since a number of major oil companies do not support the idea of gas common carriage, independent chemicals concerns are probably more likely to be direct purchasers than the majors' downstream chemicals subsidiaries. In the case of Italy, heavy ENI involvement in the chemicals sector as well as in the gas business could make common carriage initiatives less likely. Elsewhere in continental Europe, moves to buy direct are perhaps most likely in the major industrialised countries of NW Europe with developed gas industries (B,D,F and NL), since more options are available to would-be direct purchasers. One particular possibility is that large users might approach producing countries who do not as yet sell gas into the national market, as with the USSR in the case of Belgium or Algeria in the case of West Germany, for example. These producers would not be encumbered by business relationships with the importing gas utility in the markets concerned. In the UK, the common carriage system already in force and the possibility of relatively low volume direct supplies (from smaller fields) could mean that would-be direct purchasers will emerge in a number of different industrial sectors. More generally, however, the chemicals and (possibly) steel sectors are likely to predominate. Other large consumers might ultimately benefit from the emergence of a more competitive gas market, but in the short to medium term there are likely to be a limited number of potential industrial direct buyers.

6.15 For the use common carriage to proceed, it is merely axiomatic that both producer and end-consumer must see an advantage in direct supply arrangements. While industrial consumers typically have fairly short time horizons, gas producers are used to taking a very long view of the market - as evidenced by the conclusion of the Troll deal at a time of low gas prices, for example, or the direct sale of UK Miller gas to the Peterhead power station at a price which appears to be below that which British Gas might have offered, even allowing for the producers' saving in gas processing costs. Arguably, therefore, there are precedents for producers taking a strategic view where the short-term advantage appears slight, but the point remains that producers need to see a benefit to them from direct sales, be it short or long term in nature.

6.16 Few Community gas producers (outside the UKCS) have much potential gas production waiting to be sold which cannot find a place in today's market. This is true of France, West Germany, Italy and offshore Netherlands, for example. There exists the potential to step up output from Groningen, but the Dutch Government is not looking to expand gas exports any further, for long term depletion policy and supply security reasons. This means that the main potential sources of direct supplies to continental Europe in the short to medium term are non-Community gas producing countries, principally Algeria, Norway and the USSR. All of these tend to sell gas on a fairly high load factor basis, for economic (capacity utilisation) reasons.

6.17 Among the principal concerns of these potential direct suppliers of natural gas are likely to be:-

(a) buyers' take-or-pay commitments;
(b) offtake volumes;
(c) security of offtake;
(d) load factor of supply; and
(e) price and price indexation.

In relation to the non-price factors referred to above, it will generally be the case that:-

(a) most large industrial customers could only commit themselves to take-or-pay for (at most) 5-10 years ahead, as compared to 20-25 year commitments from gas utility buyers;
(b) there are very few industrial users who take more than 0.5 bcm/a, for example, but this is only equivalent to a fairly small North Sea gas field and is very small in comparison to the major international supply contracts, which are not field-specific. Although volume would not be all-important to a producer looking for supplementary outlets at the margin, there could still be a concern that relationships with a 10 bcm/a utility customer should not be put at risk for the sake of a relatively small supply increment which could be gained through common carriage;
(c) the long term future of energy-intensive manufacturing businesses in the Community is likely to face growing competition from low cost areas such as the Middle East, thus raising doubts as to the long term security of direct supply offtakes. Moreover, plant maintenance or unplanned downtime at the buyer's site could impair the short-term offtake security of direct sales, as compared to the relative stability of offtakes assured by gas utility buyers with a diversified portfolio of customers. There is also an offtake security point relating to the configuration of the European gas grid. If a consumer were seeking to buy direct from a source which would not normally be physically able to deliver gas to him, then the producer would be dependent on a gas "swap" with some other source to effect delivery. The possibility of a supply failure in the other

producing country involved would therefore imply a loss of offtake security for the country making the direct supply. If Soviet gas were sold direct to gas consumers in southern Italy or northern West Germany, for example, then those consumers might continue to get physical supply from Algeria and Norway respectively and the USSR would be adversely affected by a supply shortfall on the part of these other producers; and

(d) quite a number of large industrial buyers are able to take gas on high load factor, for chemical feedstocks, auto-generation or other process users. Where this is not the case (a minority of large users), most producers would still be looking to sell on a high load factor and the industrial user might therefore need to hire storage capacity from a gas transmission company.

6.18 In general, the non-price "package" which large industrial consumers could offer to the gas producing countries is likely to be less attractive than that which purchasing gas utilities currently provide. One way in which industrial buyers might overcome this is by forming a purchasing consortium or by acting through a trader/broker, although this might raise difficulties for them where, as large industrial concerns, they are in competition with one another. In any event, it can be argued that the direct buyer acting alone would normally have to offer a higher price than that currently paid by importing gas utilities in order to offset the non-price disadvantages which the producer may perceive in selling direct. There is, in fact, some tentative evidence that such a situation may have arisen in the past. In an attempt to break into the West German market, BP subsidiary Gelsenberg agreed an early 1980s purchase price for Norwegian gas of around $6.00/mmBtu, above the $5.50 base price for Statfjord gas delivered to the continental utilities' buying consortium at Emden. (Since then, the continental buyers have renegotiated their purchase price, while Gelsenberg have had to abandon their attempt at market entry). Similarly, Elf Aquitaine were reportedly offering a higher price for Troll/Sleipner gas they required for SNGSO than that agreed between the Norwegians and the consortium of continental utility buyers. Most recently, the base price for SEP's 2 bcm/a gas purchase from Norway is understood to be above the current "E" tariff price they would otherwise pay Gasunie, though SEP are hoping that the indexation provisions will bring the Norwegian price lower in the long term as oil prices rise in real terms. There is thus an argument that new entrants to the gas buying business might have to pay a "strategic premium" above the going market rate in order to buy their way into the market.

6.19 An important point to bear in mind is that the international gas market is scarcely a model of atomistic perfect competition. It is effectively oligopolistic/oligopsonistic, with perhaps only three or four large potential sources of direct gas supplies to consumers in continental Western Europe, informally recognised "rules of the game" and buying consortia which effectively reduce the number of independent buyers to a handful. This market is therefore unlikely to function like a perfectly competitive market, even if common carriage were to double or treble the number of buyers. Oligopolistic/oligopsonistic markets can be unstable and much depends on the strategic thinking of the significant players. This therefore raises the possibility that an industrial consumer might obtain gas at a <u>lower</u> price than the major purchasing gas utilities, if the producer concerned believes that it is thereby possible to "buy" a more than proportionate increase in market share. A producer might consider that a specific price reduction to a large direct buyer could stimulate extra gas consumption on the buyer's part. This might be achieved through substitution of low cost, low quality fuel oil, for example, increased auto-generation to displace electricity purchased from the grid or higher ammonia production levels using feedstocks of natural gas. The producer's aim would be to grant a specific discount and thus avoid having to give an across-the-board price reduction to all industrial users through renegotiations with the purchasing gas utility. This would require the producer to be fairly sure that:-

(a) its gas utility customer(s) will not immediately be able to demand and secure the equivalent price reduction; and that
(b) other producers will not perceive a threat to their market share and thus trigger off a <u>general</u> round of competitive price cutting.

6.20 The best result for industrial gas consumers would arise if at least one major producer can be persuaded to take this risk and turns out to have made a mistake, in that a <u>general</u> imported gas price reduction follows through a process of gas-to-gas competition. Whether producing countries would in fact seek to "buy" market share in this way if a common carriage system were introduced into the Community is a matter for judgement. Recent history suggests that there is a tacit understanding between the major producers that none will seek to undercut the "going rate" by very much; of all producers, the USSR may be in the best position to do so, but in practice its prices are typically only a little below those for Dutch or Norwegian supplies. If producers were to continue to take this approach, then common carriage would probably not produce a significant reduction in gas prices to industrial users. If, however, one producer seeks to "break the ring", then gas-to-gas competition could ensure and bring a general price reduction with it.

6.21 In the U.S., open access gas transportation has indeed stimulated gas-to-gas competition and resulted in significantly lower gas prices for large industrial users - typically around \$1.50/mmBtu (ECU 0.05/m^3) in mid 1988 as against a Dutch "E" tariff of some \$2.50. As we have pointed out, however, this arose in circumstances where there were very many U.S. producers with shut-in, low cost gas production and a need to find a market for cash flow reasons, combined with a substantial excess of long distance pipeline capacity. European conditions are totally different and it would be unwise to predict the same result. In the current European market situation, the impact of a common carriage system on gas import purchase prices - perhaps <u>the</u> central issue of this whole inquiry - must be regarded as an open question since so much depends on the market reaction of the major players. To the extent that past behaviour is a reliable guide to future conduct in a different environment in which common carriage were established, our view is that a very significant reduction in gas purchase prices to industrial consumers is rather unlikely over the medium term, at least.

6.22 The belief that common carriage would lead to lower border prices for imported gas supplies is almost certainly the main motivating factor for those large industrial consumers who would be interested in the opportunity to buy direct from producers. There could, however, be other advantages which they consider important, such as:-

(a) the opportunity to try to negotiate price indexation clauses which are more appropriate to their requirements; or

(b) the chance to take advantage of relatively low non-gas costs imposed on the system.

We consider each of these points in turn below.

6.23 A few very large industrial users (eg cement plants) may regard coal as a major alternative fuel to gas, as well as (or instead of) HFO. Gas feedstock users could also argue that HFO is an irrelevant marker price as regards the market for gas-based ammonia, for example. Some industrial users may therefore take the view that, especially if oil prices rise in real terms in the future, the tendency of gas utilities to link selling prices for gas to those of oil products is inappropriate and likely to make gas unduly expensive. In practice, some gas utilities have been fairly flexible in meeting coal competition (during 1984-5, for example) and in adjusting to the economics of gas feedstock use. Nevertheless, there is a general argument that large users might prefer to see whether they can negotiate something better for themselves.

6.24 The non-gas cost of supplying particular large industrial consumers may vary considerably, depending on load factor, location, delivery pressure and a number of other factors. Individual consumers with high load factors, located on the high-pressure transmission grid or near to the border at which gas is imported may consider that their gas purchase price (linked to the HFO price, for example) exceeds the current border price for imported gas, plus any non-gas (transmission and storage) costs which they impose on the system. They might therefore see advantages in a direct supply via common carriage, even though they do not expect to be able to undercut the border price already obtained by the purchasing utility. This could be the case, especially, in Member States where a "premium" fuel (eg gas oil) related gas price applies to premium industrial applications, as in the UK and West Germany.

6.25 So far, we have largely been discussing the impact of a common carriage system on those industrial users who, themselves, would be interested in seeking to buy gas direct via common carriage. It is, however, important to recall that many industrial users - especially those using gas mainly for seasonal, space heating purposes - use relatively little gas and are unlikely to be in a position to buy direct. The impact of a common carriage system on them may depend to some extent on the natural gas pricing system in force for industrial sales. To the extent that very large users are able to secure benefits from common carriage, transmission companies may then be prompted to improve their terms of supply in order to remain attractive. If there is a non-discriminary tariff system in force, then improvements offered in order to fend off direct marketing competition for very large consumers will tend to spread automatically to other users. (The transmission company would, of course, weigh up these across-the-board concessions against the cost of simply foregoing sales to the very large consumers(s) concerned). Where prices with large industrial users are individually negotiated, however, this "spreading" of competitive benefits across the industrial market is somewhat less likely to occur.

6.26 In the section on small residential/commercial users, we raised the possibility that transmission companies losing part of the market to direct sales could seek to pass more of their fixed costs (including any take-or-pay penalties) on to the remaining consumers. Many smaller industrial consumers would be protected to some extent from this by inter-fuel competition and (in some countries) by unified industrial tariff systems which make it difficult to discriminate between that part of the industrial market which is under competitive threat from direct supplies and that part which is more "captive" to the existing gas supplier. Nevertheless, there are many smaller industrial users of firm gas who do not, in the short term, have any economically attractive alternative to gas - perhaps because they do not have the space to install oil tanks on their site. Moreover, several countries do have separate tariffs for large and small industrial users which could allow a gap to open up between them in the event of a common carriage system being introduced. There is, therefore, the possibility of an adverse impact - certainly in relative and possible also in absolute terms - on the smaller end of the industrial gas market.

Power Stations

6.27 Gas-fired power stations are very much a special case among the largest users of natural gas, since their size and location on the transmission grid make them particularly suitable for a direct supply from producers. They might also be able to provide the long-term take-or-pay commitments which producers are looking for and which most industrial gas users (even large ones) are unable to provide. Particularly if gas were used for base load generation, the load factor of supply would also be attractive to producers. However, conventional, single-cycle gas stations are not generally economic to run in the base load, which is often filled by coal and/or nuclear generation. In the Netherlands and West Germany, for example, gas is currently used in the peak/middle load and this would be less attractive to producers than a base load or base/middle load sale. In Italy, ENEL run their gas stations on a higher load factor, but their multi-fuel concept (oil/gas or even coal/oil/gas stations) precludes the use of efficient gas combined cycle technology. Gas used in this way would have a value equivalent to the lower of HFO and coal prices and this is unlikely to be very attractive to a gas producer.

6.28 At current prices, the use of gas in efficient combined cycle plant may now find a place in the middle/base load. This relatively high value, high load factor use puts power companies in an even stronger position to buy direct, as illustrated by the recent reported deal between SEP of the Netherlands and the Norwegians. In the UK, where considerable extra generating capacity is required in the 1990s, the proposed electricity privatisation is giving a further stimulus to interest in gas-fired power generation and a number of new power consortia are looking at the direct purchase/common carriage option as well as supplies from British Gas. Interest in gas use in power stations is, however, country-specific; there is no demand in France, where nuclear stations predominate, and there is unlikely to be much interest in West Germany for the foreseeable future due to excess installed capacity, unless liberalisation of the European power market increases the pressure to substitute high cost indigenous coal with other, cheaper fuels. Nevertheless, there is clearly a number of Member States in which a major opportunity exists to expand gas sales into power stations. Unlike the industrial sector, where many of those seeking to buy direct would be existing gas consumers, the power sector is likely to to have a much higher proportion of potential new gas-using plants.

6.29 As discussed earlier in this section VI, we do not consider that common carriage is generally a necessary condition for efficient gas use in power stations to develop. If there is a new and attractive power station market for gas, then gas utilities will almost certainly seek to take advantage of the opportunity, especially when other gas demand is growing only slowly in mature markets. For example, British Gas, for a long period held in check by Government policy and its own perception of gas as a "noble fuel" in short supply, is now actively engaged in negotiations for sale to power stations. A certain flexibility in approach is needed to sell into the power market, as the alternative fuel to gas is frequently coal and not oil. Gasunie's policy of only selling to power stations at HFO-related prices ("E" tariff) appears to have been part of the reason for SEP's deal with Norway, which is understood to have a mixed coal/inflation rate price indexation. In general, however, it would not appear to be in gas transmission companies' interests to stand in the way of developing a new market and it would be surprising if they were to do so.

6.30 Where common carriage is having an impact in the UK is in providing new power station projects with a choice of supplier and a degree of gas-to-gas competition. Even if the new consortia or existing utilities do not ultimately buy their gas supplies direct from the producers, it is likely that the threat of competition from direct sales will secure better purchase terms from British Gas than would be the case if there were no alternative gas supplier for this attractive new market. The import option used by SEP (although probably not involving common carriage in this case) also illustrates the flexibility to secure appropriate terms which a common carriage system might facilitate. Similar competitive pressures could contribute towards the development of new, low-cost electricity generation capacity in other Member States, especially those with a need for additional power system capacity. Such Member States could include Belgium, Italy and Denmark, as well as the Netherlands and the UK. The achievement of maximum benefit might also require some liberalisation of the power sector as well as the gas sector, but gas common carriage by itself could make a significant contribution in this area.

Impact on the Gas Industry

6.31 Having reviewed the possible impact of a gas common carriage system on the three main categories of gas consumers, we now turn in this sub-section to the impact on the gas industry within the Community. The possible impact on local gas distribution companies, gas transmission companies and Community gas producers are each discussed, beginning with the local distribution companies.

Distribution Companies

6.32 As discussed in the earlier sub-section on small (residential/ commercial) consumers, it is important to be aware that the issue of impact on distribution companies does not arise at all in the United Kingdom and scarcely arises in France or the Republic of Ireland, since the gas industries are vertically integrated or very nearly so. Elsewhere, we need to distinguish between countries like Denmark, where local distributors supply virtually all ends-users apart from power stations, and those (such as Belgium, Italy and the Netherlands) where the local distributors supply mainly residential and commercial users. In West Germany, the position is intermediate in that larger Stadtwerke often have a significant (minority) portion of industrial sales in their market mix. The West German situation is also unusual in that many Stadtwerke buy gas from a regional transmission company who in turn purchase from an importing utility (usually Ruhrgas) or gas producer (such as BEB).

6.33 Before analysing these different situations in more detail, it may be helpful to make a few general remarks about the ability of local distributors to buy direct. First, many distributors take quite small volumes of gas, especially in West Germany where there are 500 local companies and in Italy where there are around 2000. Second, few have significant gas storage facilities of their own and thus typically take gas on a very poor load factor, with considerable weather-related fluctuations in offtakes. Third, many are restricted to a particular gas quality in order to permit safe utilisation in small consumers' appliances - something which is rarely a constraint for large industrial users. If they were to buy direct, many local utilities would face tougher non-price terms -

capacity charges and take-or-pay commitments - which they do not currently face. In the case of direct supplies at high load factor, they would have to pay not only for third party carriage (transportation), but also for storage in order to meet seasonal demand fluctuations. Thus the distributor would either have to take on, or pay for as "unbundled" services, all the functions which are currently exercised by the transmission company prior to supply at the city gate. Particularly for smaller distribution companies, therefore, a direct purchase would raise complex commercial and technical issues with which they are not equipped to deal. From the producer's point of view, it is also more attractive to sell to a large, secure transmission company buyer than to a large number of small distributors.

6.34 In some Member States, there is also a degree of common ownership as between transmission companies and local distributors, which makes it less likely that the latter would seek to by-pass the former and purchase gas direct from producers. This is particularly true of Belgium and Italy, for example. The private Intercom/Tractabel group who hold 33% of Distrigaz are also responsible for a significant portion of local gas distribution in Belgium, while the Italgas group (effectively controlled by SNAM as dominant shareholder through their 40% interest) accounts for some 25-30% of all gas distribution in Italy, often in joint venture with the municipality concerned. In these circumstances, direct purchasing by the local distributor appears particularly unlikely.

6.35 There are also contractual barriers to common carriage in some instances, as in the Netherlands. VEGIN, the association of Dutch gas distributors, is committed to purchase the gas it requires exclusively from Gasunie, under the terms of an "evergreen" long term contract. Even if VEGIN were in a strong position to deal direct with producers - which it is not, for the reasons set out in the previous paragraph - it would still be in breach of contract if it attempted to do so.

6.36 In the West German situation, there is a further possibility not encountered elsewhere. Those local distributors who currently buy from a regional transmission company (Bayerngas, Gas Versorgung Suddeutschland etc) could conceivably by-pass the regional company, but stop short of dealing direct with gas producers. Thus they might purchase gas from an indigenous producer (such as BEB) or importing utility (such as Ruhrgas) and seek carriage through the regional system. An argument could perhaps be made that regional "middlemen" do not exist elsewhere in the Community and could therefore be cut out of the market in West Germany as well if common carriage were introduced. In practice, however, the ownership of the regional transmission companies makes this rather unlikely. Most were originally set up in order to develop regional markets by local municipalities, Laender governments and gas distributors. Ruhrgas now also has a stake in several of them, following financial difficulties and a need for new equity injections. Bayerngas, for example, is currently owned by the Bavarian Government, Munich, Augsburg and other Bavarian municipalities - although it is now understood to be inviting new shareholders (including Ruhrgas and power company Bayernwerk) to participate. In such circumstances, a concerted move by "national" transmission and local distribution companies to by-pass regional transmission companies is rather improbable; this assessment is currently reinforced by the bilateral Demarcation Contracts between transmission companies (both national and regional). Finally, it is conceivable that transmission companies could seek to "pick off" and supply direct via common carriage those industrial customers currently supplied by the local distributors. This would currently fall foul of the local Concession Contracts held by the distributors with the municipality. Leaving these on one side, it is unclear whether the industrial user would have much to gain from deserting the distribution company, since the market-related industrial gas pricing policies pursued by West German distributors and transmission companies are generally very similar if not the same.

6.37 To take another example, we can also consider the position in Denmark. This is unusual in that Dangas currently has just 7 customers - one power station, the Copenhagen municipality and 5 regional distribution companies - while all final consumers except the power sector are supplied by the distributors. There is therefore the possibility that, with common carriage, the distributors could seek to deal direct with producers (either DUC or perhaps the Norwegians) while Dangas could seek to sell direct to large industrial consumers. Currently, Dangas and the distributors share the profit margin in each market, but the industrial market is barely profitable, so that Dangas might see little advantage in direct sale for as long as this situation prevails. As far as distributors' direct purchases from producers are concerned, it would perhaps be surprising if they could individually negotiate such a favourable deal as Dangas could, given the smaller volumes involved. Moreover, it would probably need a single large purchaser to justify the construction by the Norwegians of an export pipeline link.

6.38 It is clearly important to look carefully at the particular situation in different Member States in order to make a realistic assessment of the impact on distribution companies. Having considered a number of examples, our view is that very few local distributors are likely to be both willing to try to purchase direct and also in a strong negotiating position to do so. We therefore take the view that the vast majority would be likely to continue to purchase from their existing transmission company supplier.

6.39 As discussed earlier in this section, there is the possibility that transmission companies faced with a loss of large industrial consumers to competition from direct marketing might seek to recover a larger proportion of their fixed transmission, storage and take-or-pay costs (if any) from distributors who would be in a weaker position to buy direct. In some Member States, the interests of distributors might be protected to some extent by the attentions of national authorities such as the Italian Inter-ministerial Pricing Committee, the Belgian Comite de Controle or the West German Kartelamt. Nevertheless, some disadvantage to distributors could probably still arise if common carriage really put a squeeze on the transmission companies' current profit margins and they sought to pass some of the squeeze on to their local distribution customers.

Transmission Companies

6.40 From the axiom that common carriage will only develop if both producer and end-consumer see benefits in direct marketing arrangements, it follows that common carriage would normally work to the disadvantage of the transmission companies in the middle and this is reflected in the arguments against a common carriage system which some of them have raised, either publicly or in material presented to DG XVII. The adverse impact of common carriage on transmission companies could include:-

(a) simple loss of revenue, if large industrial users or power plants opt to purchase direct from producers and not from them;
(b) resulting take-or-pay penalties under the terms of their gas purchase contracts; and
(c) a possible increase in unit fixed non-gas costs in the remainder of their market, which they may not be able to pass on to consumers.

Each of these factors is considered in turn below.

6.41 Especially for "pure" transmission companies, a profit is normally earned through ensuring high utilisation of equipment (pipelines and storage) in order to keep unit costs low, coupled with a small unit trading margin on a high volume of throughput. Given the importance of fixed costs in the industry (non-gas capacity costs plus gas purchase contract take-or-pay commitments), the costs saved when any given load is lost are often minor - particularly in the short run. Consequently, revenue foregone from a loss of customers to direct marketing could rapidly eat into the profit margin on the transmission companies' remaining business.

6.42 Take-or-pay commitments are a particular example of the fixed cost point. Although most gas purchase contracts allow offtake flexibility around the annual contract quantity (ACQ), several transmission companies are currently taking gas at or near minimum bill levels only and this means that any further reduction in offtakes would push them into take-or-pay penalties. Those transmission companies taking volumes nearer to the full ACQ under their contracts (such as the West German importers or British Gas, for example) would have more flexibility to absorb a loss of load without incurring take-or-pay penalties. The impact of going into take-or-pay would be to incur a cost which cannot easily be recovered in the market. Transmission companies could try to spread the cost over their remaining customers, but inter-fuel competition might make it difficult for them to do so without risking further loss of load - this time to competing fuels rather than to direct sales.

6.43 While take-or-pay penalties are tantamount to an increase in unit gas costs, it is also conceivable that common carriage could lead to an increase in transmission companies' unit non-gas costs in their remaining market. This would be the case, especially, if transmission companies were obliged to provide firm carriage at marginal cost only (see Section V), rather than full average costs including fixed costs. Even if full cost charges are accepted, there is still a possibility that the transmission and storage system might be less effectively used. For example, a large firm gas consumer might decide to purchase direct from a different source than that from which he is currently supplied by the transmission company. He would then have to compensate the transmission company for any extra compression or loop lines required to provide for gas carriage along the new route, but would leave unused pipeline capacity on the old supply route. The consumer might also be prepared to take more of a supply risk than the transmission company, perhaps because he can invest to make an alternative fuel available in the event of interruption. Thus it may well be that transmission and storage capacity set aside by the transmission company to meet the customer's requirements are no longer fully utilised. This will not always be the case and sometimes the transmission company may be able to use the capacity released in such facilities to meet the growing demands of other customers for whom new capacity would otherwise be required. Nevertheless, it is generally true (especially in slowly growing markets) that common carriage make it more difficult for transmission companies to plan and operate their systems in such a way as to achieve high utilisation and low unit costs.

6.44 The ability of utilities to absorb such adverse developments is very varied. While Ruhrgas and British Gas are healthy, profitable businesses, for example, other transmission companies such as Distrigaz have only been marginally profitable in recent years and the financial position of Gaz de France remains precarious. Much may also depend on the extent of competition from direct sales and the way in which the transmission companies are able to react and adapt to the new circumstances. The view we have reached in this study is that, over the short to medium term (which in the gas industry means the period to around the turn of the century), the use of common carriage by existing customers of the transmission companies (as opposed to new power plants, for example) is generally unlikely to be all that great. It nevertheless remains true that, in some instances, the loss (or even partial loss) of only one or two very large loads could have a serious impact on individual transmission companies' total gas sales. This is particularly true of large gas-consuming power companies such as ENEL in Italy or SEP in the Netherlands, who each account for around one-fifth of total gas sales in the country concerned. ICI alone takes some 5-6% of British Gas' total sales at its various manufacturing sites and there are several other large consumers around Europe who account for significant (if smaller) proportions of total demand in "mature" gas markets. The problem is even more acute in smaller, "new" gas markets (Denmark, Ireland, Spain and, in future, Greece and Portugal) where demand is likely to be dominated by a relatively small number of large users for some time to come. In Luxembourg, the steel industry participates in SOTEG and accounts for a large proportion of its gas sales. These smaller gas markets present special problems in relation to common carriage which we return to below. As for the "mature" gas markets, the short to medium term impact of common carriage should not be exaggerated, but is at least potentially significant in some particular Member States.

6.45 The ways in which transmission companies might react and adopt themselves to the threat of direct sales competition include:-

(a) a reduction of their own selling prices to meet any lower prices available direct from producers. This would be particularly problematic for transmission companies who sell on a non-discriminatory tariff basis, since a competitive threat to one large customer could only be met at the expense of across-the-board reductions to other industrial users;

(b) a renegotiation of purchase contract prices in order reflect the lower value of gas in an environment of (limited) gas-to-gas competition, in order to avoid take-or-pay problems. This strategy is most effective only if the renegotiation takes place before consumers are actually lost to direct sales competition;

(c) more cautious policies in terms of investing in capacity and concluding gas purchase contacts in advance of need. A number of transmission companies on the continent have already contracted supplies to cover demand through to 2000 or beyond and in future they might decide not to commit themselves so far ahead, in case part of the market is lost to direct sales competition. This could, in turn, have adverse implications for gas supply security through an impact on large new gas production projects with a long gestation period and we consider these implications below;

(d) a change in business outlook to one which seeks to earn a profit from carriage for third parties, as well as from traditional gas trading activities. This has certainly proved the case for some US pipeline companies, who have found that transportation may require lower overheads than merchanting. In the Community, revenue earned from providing "unbundled" transportation, storage, back-up or quality adjustment services could also help to offset any sales revenue lost to competition from direct sales.

6.46 We therefore consider that transmission companies, who will remain major suppliers of natural gas and who have many years of commercial gas industry experience behind them as well as a powerful market position, will generally find ways in which to mitigate the adverse impact upon them. The major danger for them remains the loss of sufficient load to force them into take-or-pay under their gas purchase contracts, since the magnitude of the resulting financial burden would often be too large to mitigate to any great extent, especially in the short term. If, as we expect, the actual "take up" of common carriage opportunities remains modest, then the impact would probably be manageable for most large transmission companies in the "mature" gas markets. Nevertheless, the possibility of the "flood gates opening" as far as the transmission companies are concerned may raise questions regarding the "management" of transition from the present position to a more open internal gas market.

Community gas producers

6.47 As outlined in section II, the most important indigenous Community gas producing countries by some considerable way are the UK and the Netherlands. Their respective positions are very different, however, in that the Netherlands has long been a gas exporter, while the UK Government has in the past prevented gas exports and there is still no pipeline link to the continent. There are also smaller gas producers to be considered, such as Italy, West Germany, France, Spain, Denmark and Ireland. Four Member States (Belgium, Greece, Luxembourg and Portugal) have no significant gas production of their own.

6.48 The Netherlands is in the unusual position of having an excess of productive potential over current sales, but no interest in expanding its gas exports. Significantly, however, there appears to be no unsatisfied "queue" of indigenous fields waiting to find a place in the market. New offshore and smaller onshore fields are generally accommodated when ready by reducing Groningen output and some Groningen gas is thus reserved for the longer term needs of export customers and the domestic market. Even if Gasunie ceased to have right of first refusal over buying new indigenous gas fields, it would be surprising if producers could find a better sales deal elsewhere. Groningen gas would continue to be under contract to Gasunie and this constitutes the bulk of remaining Dutch gas reserves. It therefore seems most unlikely that the Dutch fields would be marketed directly through common carriage, even if such a system were established. Relatively low production costs also mean that the incentive for Dutch gas exploration and production would be reasonably secure, even if common carriage were to bring about some general long term reduction in bulk gas purchase prices.

6.49 Although the UK does not have a very high proven gas reserves/production ratio by international standards (currently under 15 years), probable reserves could double that figure and projected productive potential in the 1990s appears to exceed projected UK gas demand. Even at today's relatively low oil and gas price levels, there is an informal "queue" of UK fields waiting for a place in the gas market. Some UK producers might therefore be interested to explore the opportunities for gas exports to the continent, especially as gaps between potential purchasers' projected gas demand and their currently contracted supplies being to open up in the longer term. As things stand, this would require the UK Government to waive the "landing requirement" for gas (referred to in section IV), though the Commission may consider that this requirement is incompatible with an open internal Community gas market. The opportunities for gas exports from the UK - which would require some sort of cross-channel pipeline link for the first time - might well be considerably greater if a common carriage regime existed in continental Member States of the Community. For example, the continental transmission companies might have misgivings (which large continental consumers do not share) about entering into competition with British Gas for supplies from the UKCS. Apart from a full pipeline link direct across the channel, there are lower cost options which could be economic on the basis of smaller gas export volumes. These include a link from a UK Southern Basin field to the Dutch sector of the North Sea or perhaps a short pipeline connection to the Norwegian Zeepipe, which will carry gas from the Troll/Sleipner area to Zeebrugge from the mid 1990s. This raises important questions of reciprocity - if Norwegian gas were entitled to make use of common carriage through onshore gas pipelines in the Community, then it seems reasonable that gas produced within the Community should not be refused access on comparable terms to offshore lines within the Norwegian sector of the North Sea. As regards the direct sale of gas from UKCS fields to UK consumers, there is already a common carriage regime in place (as discussed in section IV) and Community-wide initiatives would therefore have relatively little additional impact in this respect.

6.50 Turning to other Community gas producers, there is likely to be little impact on French indigenous gas, since Lacq has low costs and a secure outlet and it is now considered unlikely that further significant reserves will be identified, either onshore or offshore. In West Germany, all the indigenous gas that is produced can readily find a place in the market, without common carriage. However, the small size of fields and the prevalence of sour gas which needs processing before delivery mean that returns to producers are typically low and the Provincial Government of Lower Saxony has recently (October 1988) recognised this by abolishing all royalties on production, leaving only standard corporation tax to be levied. A significant fall in gas import prices due to gas-to-gas competition through common carriage could therefore damage incentives for further exploration, as could any move by transmission company purchasers to offer a lower level of take-or-pay commitments. Ultimately, however, the extra supply security of indigenous gas and the seasonal flexibility afforded by the sweet gas portion of West German output could command a premium over the price of high load factor gas imports from outside the Community. For the foreseeable future, most Italian gas production will continue to be in the hands of Agip and will therefore continue to be sold to fellow ENI subsidiary SNAM, even if a common carriage right is established. Some independent producers may, however, be interested to sell their gas direct to consumers on the SNAM grid, as well as to those on the small, independent SGM (Montedison/Elf/Petrofina) grid as they do at present. This is because SNAM appears to pay a rather low price for the gas which it currently purchases from them. As for the smaller gas producing countries in the Community - Denmark, Ireland and Spain - the advantages of a secure, national energy supply which can displace imported oil are such that indigenous gas is always likely to find a place in the home market, even if a common carriage system is established.

6.51 It is naturally a concern of the European Commission that the introduction of a common carriage system for the transportation of natural gas should not prejudice the future level of indigenous Community gas production, through damaging incentives for exploration and field development. Such damage might occur if gas-to-gas competition brings about a significant fall in the general level of gas prices or if transmission companies react to the threat of competition by offering less generous take-or-pay and other contract terms. For supply security and general economic reasons, Member State governments will normally be keen to promote the development of indigenous reserves and there is room for a further relaxation of the oil and gas tax regime in most instances if this were necessary to maintain momentum in exploration and production. Although it is conceivable that the impact of common carriage might push some marginal gas fields into non-viability, we would not expect the impact to be so severe as to place a significant brake on the general pace of indigenous gas development. Unfortunately, the long term prospects for indigenous production in a number of Member States (France, West Germany and perhaps also Italy) are rather poor, regardless of whether a common carriage is introduced or not.

Impact on the Community as a whole

6.52 Having examined in some detail the likely impact of gas common carriage on different classes of consumers and on the various parts of the gas industry within the Community, we turn now to an assessment of the impact on the European Community as a whole. This assessment reflects the considerations of overall resource cost discussed earlier in this section VI and the Community's energy objectives outlined in section II. Before dealing in turn with the principal advantages and disadvantages of gas common carriage, it is perhaps worth re-emphasising that we believe its impact would be rather less than it might be in the electricity sector, at least in the short to medium term. Common carriage in electricity might rapidly permit (for example) West German industrial consumers to purchase electricity from the French nuclear capacity surplus at significantly lower prices than they currently pay for indigenous power output. Gas common carriage, by contrast, is unlikely to provide such immediate benefits - even for most large industrial users. The development of a more open internal market in the context of the European gas supply situation is likely to be a rather gradual, long term process. This may also have advantages, in terms of managing the process of transition from today's market to a more open, competitive situation, with a view to maximising potential benefits and mitigating potential drawbacks. Our view, in general, is that some protagonists and some detractors of the common carriage idea have overstated its likely impact, as least as regards the short to medium term. Gas supply is a very long term business and it is therefore perfectly valid to take the long view of common carriage. The more extended the timescale over which its effects may be felt, the better will market players be able to adjust to a new business environment.

Advantages

6.53 In our view, the main potential advantages of a gas common carriage system include:-

(a) the possibility that gas-to-gas competition in the context of abundant gas reserves internationally could lead to a reduction in gas costs for large industrial users in energy-intensive sectors, such as chemicals and steel. Our view is that any such reduction due to common carriage will probably be modest, given the oligopolistic structure of the gas market in and around Europe. Nevertheless, even a modest energy cost reduction could significantly improve the competitive position of European manufacturers in international markets for certain bulk, "commodity" industrial products. They would also reduce raw material prices within the Community for higher value products derived after further processing. If such benefits can be achieved, then this could be expected to feed through into somewhat better external trade, output and employment prospects for the Community as a whole. It should perhaps be re-emphasised that the ability of even very large industrial users to negotiate lower gas import prices than those currently achieved by the existing transmission companies is unproven and the extent of any benefits such as those described above is thus highly uncertain;

(b) a possible reduction in gas selling price disparities between comparable industrial customers in different Member States. This point applies particularly to countries (such as the United Kingdom and West Germany) where high profit margin sales may be made at gas oil related prices to large "premium" firm gas consumers using gas for process purposes on a high load factor. Such consumers could probably reduce their gas costs by direct purchasing, even if they are unable to undercut the bulk price currently paid by their transmission company supplier, since the carriage charge could well be lower than the transmission company's current gross margin. This would then reduce the disparity between their gas costs and those of comparable consumers elsewhere (such as Italy and the Netherlands) who are already offered firm gas at a price related broadly to fuel oil prices. Particularly in energy intensive sectors, such developments would then ensure more even competition for industrial products within the Community. Nevertheless, certain gas selling prices differences are likely to remain, for reasons which common carriage does not address, such as different underlying costs (eg for storage capacity);

(c) increased competitive pressure on the gas industry within the Community to operate efficiently, prune overheads and market effectively in order to increase gas penetration and reduce unit non-gas costs. For reasons outlined in Section III, we would expect any such benefits to be rather modest, since that part of the gas industry which would come under most competitive pressure (transmission company operations) tends to have low unit non-gas costs already. Unless distributors have a significant industrial market of their own (as in Denmark or, to a lesser extent, West Germany), the competitive pressure brought to bear on them by the introduction of common carriage is likely to be less marked;

(d) the opportunity to develop efficient, environmentally acceptable gas combined cycle power stations at low cost, in view of the competition to supply these attractive new customers which common carriage could promote. The power sector now represents a major marketing opportunity for gas in a number of Member States and one of the great attractions from an economic welfare viewpoint is that, with essentially cost-based pricing of electricity, much of any benefit which common carriage might bring in terms of lower cost gas supplies to the power sector would be passed on to the consumer. There is a widespread concern, in this context, that the 1975 Council Directive on the use of gas in power stations should not present an obstacle in this regard; and

(e) an increased likelihood that UK gas exports might actually find a place in the continental market of sufficient size to justify some form of cross-channel link. This would open the way for the increased integration of the Community's second largest producing country into the European gas grid, with consequent benefits for gas supply security in the Community as a whole.

Drawbacks

6.54 To be set against the major potential advantages of a gas common carriage system for the Community, we would list the following as the most important potential drawbacks:

(a) the danger that, with only a handful of large gas producers selling into the Community and increased competition among an enlarged number of buyers, common carriage might actually lead to a "bidding up" of gas purchase prices. A significant "bidding up" is perhaps unlikely in the present situation of a buyer's gas market, but this might change in future if the world returns to a situation of perceived oil scarcity, high oil prices and thus renewed pressure for significantly increased gas supplies to "mature" gas markets which are now growing only slowly;

(b) a possible increase in gas prices to gas consumers who are not themselves in a position to purchase gas direct. This point is discussed at length earlier in this Section and relates to possible attempts by gas utilities to recover higher unit fixed costs from remaining customers in the event that significant industrial or existing power station load is lost to competition from direct sales via common carriage. These might include costs arising from transmission company purchase contract take-or-pay penalties and additional non-gas costs arising from less efficient use of the grid;

(c) the possibility that, in defending themselves against the threat of competition and increased demand uncertainty created by direct marketing, transmission companies would be more reluctant to purchase gas well in advance of need, offer substantial purchase contract take-or-pay commitments or make major new additions to the grid to cater for projected demand increases. This could then have adverse consequences for new gas production projects, both within and outside the Community. There could then be a long-term deterioration in the security of gas supplies to the Community as a result. Our view is that, on the likely scale of common carriage which might reasonably be expected, the extent of any such measures is unlikely to be very great. Moreover, some gas producers (such as Algeria or the USSR) could probably make significantly more gas available without major new investments which would need to be underwritten by buyer's long-term take-or-pay commitments;

(d) failure on the part of gas utilities to invest and purchase gas as required to ensure supply security, as a result of adverse consequences of direct marketing competition on their financial position. In practice, such consequences would probably be offset to some degree by utilities' earnings from the provision of transportation and other services for third parties. Once again, the impact would very much depend on the scale of contract carriage and the pace with which the common carriage system began to be used by third parties; and

(e) any adverse impact on the development of "new" or "infant" gas industries in countries such as Denmark, Spain, Greece and Portugal. At the early stage of gas industry development, a high proportion of sales is typically accounted for by a few large users such as power plants ammonia manufacturers, other chemicals plants and energy-intensive metals industries. In Greece, for example, we estimate that around 30% of total gas sales in the year 2000 may be accounted for by just 6 customers, with other industrial users taking a further 40% of gas supplies. The base load provided by such large industrial customers is then the basis for take-or-pay commitments made to gas producers, the initial construction of the principal transmission pipelines and the cash flow required to service loans and finance further grid development. Construction of distribution grids and connection of smaller residential customers often tends to be a more gradual process and the stability of industrial sales is crucial for the interim period. Whatever the merits of gas common carriage in "mature" gas markets, the imposition of such a system on "new" gas industries could place very severe obstacles in the way of their development. New gas utilities could not afford to commit themselves financially and contractually if there was a risk that their largest customers would seek to purchase gas direct from the producers. In some of these countries, the extensive role of the public sector could make direct buying less likely and geographical isolation from the integrated European gas grid (as with Greece and Ireland) is another mitigating factor. Nevertheless, there is a crucial distinction to be made here between "mature" gas industries with established markets and pipeline systems and those which are still in the early phases of development.

Implications

6.55 Should the European Commission ultimately consider that the potential advantages of common carriage outweigh the potential drawbacks, it will be important to seek ways of minimising the extent of the drawbacks that could arise. We take the view that two issues are crucial:

(a) "management" of change to ensure a smooth transition from the present situation to a more open, competitive market, in such a way that would minimise uncertainty and allow gas utilities to continue to plan, invest and purchase gas for the long term; and

(b) careful handling of "new" gas industries in order to avoid the potentially adverse affects identified above.

6.56 One way of handling the transition process might be to develop a phased introduction of common carriage and to set limits on the extent of common carriage at each stage. Purely for illustrative purposes, the Commission might develop a timetable along the following lines:

1992 - 1994	: dismantling of statutory exclusive and preferential rights, together with contractual arrangements giving effect to exclusivity;
1.1.95	: introduction of a (qualified) obligation on gas utilities to provide common carriage for other utilities and end-consumers using more than (say) 2 mcm/a, where this right does not already exist under national legislation;
1995 - 1999	: limitation of the obligation on any gas utility to provide common carriage to a maximum of (say) 5% of its own sales;
2000 - 2009	: increase in the common carriage obligation to (say) 10% of sales.
2010 -	: further increase, to be decided in [2002] within the range 15-25%.

The limits on common carriage obligations would probably relate to carriage services involving consumers within the utility's own supply area, with a quantitatively unlimited (but nevertheless qualified) obligation to provide services for gas in transit to other utilities or consumers in other areas. National governments (in the UK, for example) should have the option to set higher (but not normally lower) limits at their option, including the possibility of no limit at all within national boundaries.

6.57 The aim of such a timetable would be to create as much certainty as possible about the process of transition and to preclude from the outset the risk that the mere possibility of unlimited carriage would interfere unduly with orderly business planning, purchasing and investment for the longer term on the part of existing utilities. Under these arrangements, the Commission might reserve to itself the right to review some of the key parameters periodically in the light of market developments, but within a specified range. Thus, for example, the upper limit on the carriage obligation for 2000-2009 might be open for review in 1997, but within the range of (say) 8-12%. There are many variations on this broad schema which might be considered, but the principle would be to recognise that gas utilities have already taken key decisions which will affect the shape of their business through to 2000 and well beyond. The further into the future a very major common carriage obligation is placed, the better they will be able to adjust their business activities accordingly. In the meantime, a modest common carriage obligation in the 1990s would probably cater for the majority of those who might seriously wish to take advantage of the new system.

6.58 The Commission might also define "new" gas industries, perhaps in terms of those Member States falling below a given level of gas consumption per head of population. These might include Denmark, Greece, Ireland, Portugal and Spain. The national governments of these Member States could then be given the option of a much more gradual timetable for the introduction of common carriage in these instances - probably including a complete moratorium for a period in order to allow the gas industry to become properly established.

6.59 These implementation issues clearly require more discussion and the above should be regarded as tentative suggestions only at this stage. Our view is nevertheless that, if the Commission did decide to introduce gas common carriage, the manner of its introduction is of the utmost importance. Whether or not there would ultimately be net advantages in common carriage transportation for natural gas, it will not be in the interests of the Community as a whole to create the kind of uncertainty which has characterised recent U.S. experience of open access transportation. The U.S., with a very different gas supply situation, can arguably take the risk of operating largely on a short term basis with many of the "rules of the game" as yet undecided; the European Community, with its much greater dependence on a very few external gas supply sources, most assuredly can not.

APPENDICES

APPENDIX A

COMMON CARRIAGE IN THE USA

STRUCTURE OF THE UNITED STATES NATURAL GAS INDUSTRY

Organisation

A1.1 Prior to the widespread introduction of natural gas in the post World War II (WWII) era, the gas industry in the United States was vertically integrated. Low BTU gas was manufactured and distributed by local distributing companies (LDCs).

A1.2 As the gas industry metamorphosed into the "natural gas" industry, vertical integration (while not disappearing) was no longer the general rule. A number of different structures emerged from this change and currently exist. A non-exhaustive compendium follows:

(1) LDCs with a merchant pipeline as the sole source of supply;[1]

(2) LDCs with multiple merchant pipeline suppliers;

(3) Either of the above with the LDC supplying its own peak shaving and/or storage capability;

(4) Either (2) or (3) above with the LDC having a local source of natural gas production;

(5) Merchant pipelines with LDC subsidiaries and/or affiliates;

(6) Merchant pipelines buying their supplies from producers.

(7) Merchant pipelines with exploration and production subsidiaries and/or affiliates; and,

(8) Merchant pipelines offering transportation services.[2]

1/ Typical pipeline tariffs for small LDCs and for "full requirements" LDCs (i.e., no contract demand) have, at least until now, not permitted the customer to take gas from another source.

2/ Although until now reluctant to or refusing to transport gas other than their own supplies.

(9) Brokers are a relatively recent addition to the industry structure. Their function is to assemble supply packages and to bring producers to the end user market.

A1.3 With regard to gas exploration and production, oil companies were the original players along with independent producers. For sometime now, pipelines and LDCs have also been involved in exploration and production.

Natural Gas Supplies

A1.4 The most important gas producing area in the U.S. is the Gulf of Mexico, which according to the American Gas Association (AGA) holds 23 per cent of the reserves and accounts for 28 per cent of the production in the lower 48 states[3]. Gas supplies have been found in thirty-one (31) of the lower (48) states and in Alaska. An indication of the degree to which gas supply is dispersed in the lower 48 states can be found in an AGA report of natural gas findings during 1987[4]. Findings have been reported in the following eighteen (18) states:

ALABAMA (ON & OFFSHORE)	NORTH DAKOTA
ARKANSAS	OHIO
CALIFORNIA (ON & OFFSHORE)	OKLAHOMA
COLARADO	OREGON
KANSAS	PENNSYLVANIA
LOUISIANA (ON & OFFSHORE)	TEXAS (ON & OFFSHORE)
MICHIGAN	WASHINGTON
MISSISSIPPI (ON & OFFSHORE)	WEST VIRGINIA
NEW MEXICO	WYOMING

3/ From the AGA Publication Exploration 1987.

4/ Ibid

A1.5 Natural gas is found both on and offshore and in a variety of geological formations. Wells vary from shallow water, shallow depth drilling in the Gulf of Mexico up to 17,000 feet[5] or greater in onshore areas. It should be noted that all gas found in the federal offshore domain must be dedicated to interstate commerce.

Transportation Network

A1.6 There are a total of 253,656 miles of interstate pipeline in the gas transportation network, which serves the lower 48 states. Of this total, 184,634 miles are transmission pipe. The remainder consists of 64,468 miles of production field pipe and 4,554 miles of storage pipe.

A1.7 In addition, there are many intrasate natural gas pipelines. While the network cannot directly accommodate all possible transportation transactions, many indirect deliveries can be accommodated through displacement. The extent of the interstate network is displayed overleaf on the FERC map entitled, "Major Natural Gas Pipelines - October 31, 1985".

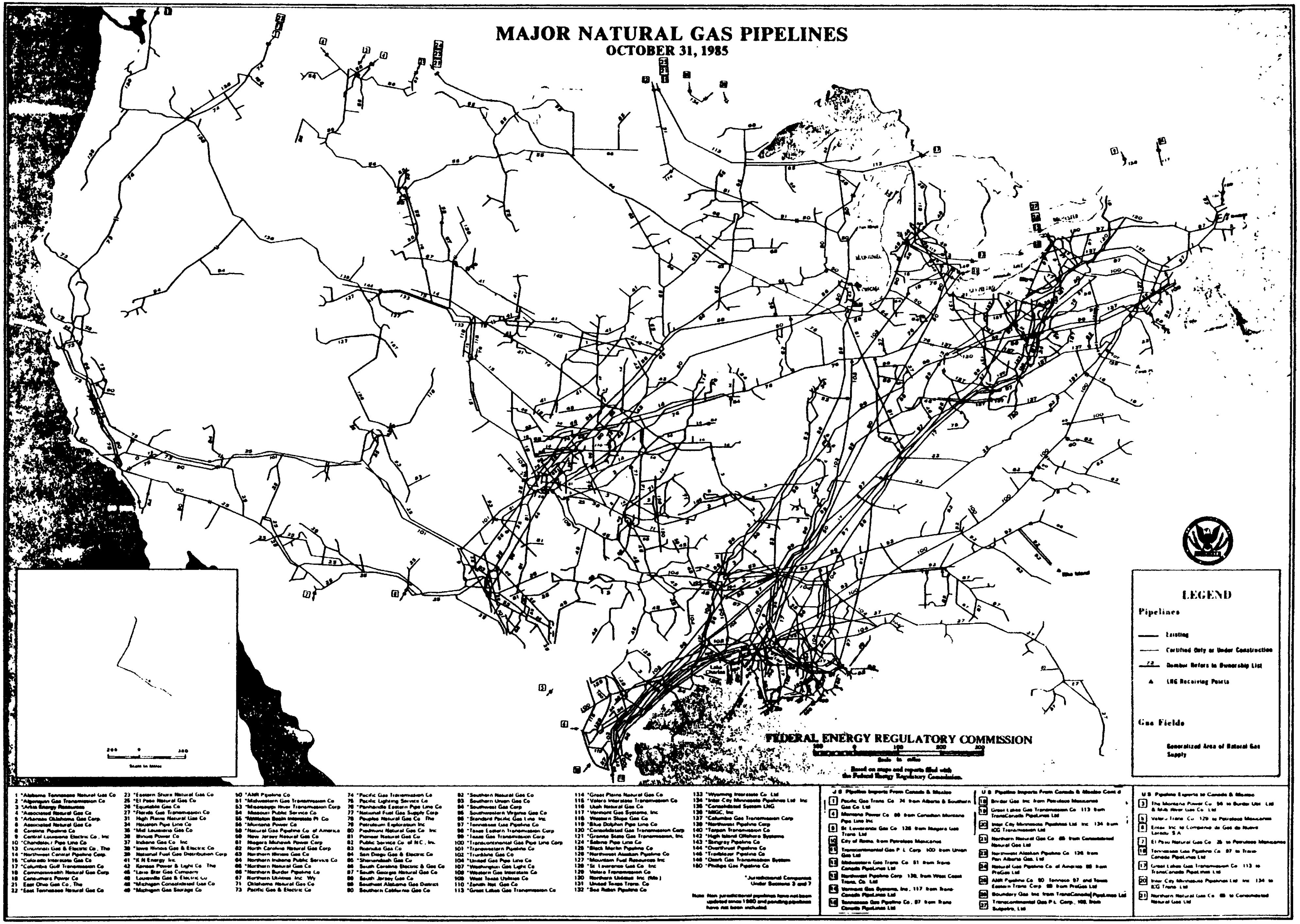
A1.8 The United States has extensive underground storage capacity for natural gas. As of March 1986, there were nearly 400 active underground storage reservoirs across 26 states, with a combined capacity of just over 8 trillion cubic feet (tcf). Of this capacity, about 80% is in depleted gas fields and the remaining 20% in natural acquifer pools. The working volume in gas storage is about 4 tcf, currently equivalent to over 25% of total annual gas consumption.

Market Structure

A1.9 The major players in the marketing of natural gas in the U.S. are the LDCs who in 1987 accounted for some 86 per cent of the total gas sales made by the major interstate pipelines. Additionally, a very large percentage of the gas transported in 1987[6] was transported for the account of LDCs. Some part of this latter includes transportation by LDCs for their large industrial customers. The LDCs market directly to residential, commercial

5/ Ibid

6/ At this writing, the actual statistics are unavailable.


MAJOR NATURAL GAS PIPELINES
OCTOBER 31, 1985
LEGEND
Pipelines
Existing
Certified Only or Under Construction
Number Refers to Ownership List
LNG Receiving Points
Gas Fields
Generalized Area of Natural Gas Supply
FEDERAL ENERGY REGULATORY COMMISSION
Scale in miles
Based on maps and reports filed with the Federal Energy Regulatory Commission
FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON D.C. 20426

and industrial end users in their service territories. Currently, the acquisition of gas for use in the generation of electricity is split between pipelines and LDCs.

A1.10 The large industrial customers of both pipelines and LDCs who can switch between natural gas and alternative fuels have been, as will be seen in a later section of this overview, a major force in the move towards open transportation of third party gas.

A1.11 As of 1985, the pattern of natural gas consumption in the United States was as follows:-

Market sector	Number of customers	% of gas consumption	Consumption (t.c.f.)	Gas share of market
Residential	55 million	28%	5.5)	48%
Commercial	3.8 million	15%	2.4)	
Industrial	189,000	37%	5.9	35%
Power utilities	1,800	19%	3.0	12%

In the U.S. oil has a relatively low (17%) share of residential and commercial energy consumption. Many industrial gas consumers can readily switch to using oil, as can a considerable number of gas-using power plants. The most important fuel for U.S. power generation, however, remains coal with a 55% share of the market.

A1.12 Currently, around 60% of U.S. gas supplies come from indigenous production by the oil company majors, with a further 35% supplied by independent U.S. producers and 5% from imports (almost all from Canada). Some two-thirds of this gas is sold into intersate market and the other third is marketed locally through intrastate pipeline networks.

A1.13 As of autumn 1986, the Energy Information Administration reports the cost and price structure of th U.S. gas market to have been as follows:-

	$/mcf*
Average wellhead price	1.54
(Typical Texas & Gulf Coast spot market price)	(1.39)
Average transmission cost plus return	1.48
Average City Gate price	3.02
Average Residential Price	6.26
Average Commercial Price	4.84
Average Industrial Price	2.81
Average Electric Utility Price	2.12

(* denotes 1000 cubic feet)

A1.14 The low gas prices for industrial users and (especially) power plants reflect both the low level of fuel oil prices at the time and also the use of spot purchases and gas transportation to achieve delivered gas prices significantly below the average city gate price for sales from pipelines to LDCs.

LEGISLATIVE AND REGULATORY FRAMEWORK

A2.1 What follows is an overview of the legislative and regulatory framework within which the U.S. natural gas industry operates. It is a non-exhaustive overview and touches only the principal features.

A2.2 The natural gas industry in the United States is subject to legislation and regulation at the national, state and local levels. All aspects of the industry deemed to be interstate in nature are governed at the federal level. The two major legislative mandates are the National Gas Act (NGA) of the 1930s and the National Gas Policy Act (NGPA) of 1978.

A2.3 Regulation of the industry at the federal level is the responsibility of the Federal Energy Regulatory Commission (FERC, or the Commission), formerly known as the Federal Power Commission (FPC). In addition to its responsibilities with regard to interstate commerce, the FERC is also charged with the establishment and enforcement of national energy policies that may limit the freedom of the individual states in the regulatory arena. A good example of this latter federal power was the establishment of a nationwide system of priorities, with regard to the attachment of new natural gas customers, because of scarcity of supply. The use of natural gas for boiler fuel was severely curtailed and even forbidden.

A2.4 Turning now to the state level, we find at least two different modes of regulation. Almost invariably, investor-owned utilities (IOUs) are regulated by a state commission. There are, however, some exceptions, such as New Orleans Public Service, Inc. (NOPSI), which is regulated by the city. Municipal systems may or may not be state-regulated; if not, it is usually the city council that provides regulation.

A2.5 Federal regulation takes many forms: accounting regulation takes the form of the required use of the FERC's Uniform System of Accounts; construction is regulated through hearings to determine whether or not to certify a project, i.e., issue a Certificate of Public Convenience and Necessity so that work can proceed; tariffs are regulated through rate hearings in which specific exhibits must be prepared and in which public intervention is permitted; and the FERC must see that the requirements of other federal agencies, such as the Department of Transportation (DOT) and the Environmental Protection Agency (EPA) are met.

A2.6 State regulation has, in the past, tended to focus on tariff regulation, costs and consumer protection. There is currently a movement among state regulatory bodies to require least cost planning on a jurisdictional basis, even if a utility is trying to optimise its system over more than one jurisdiction; and some states with local natural gas production are urging utilities to buy from sources within the state. It is likely that state commissions will act to limit the amount of take-or-pay obligations that LDCs can pass on to consumers. The states will also intervene in cases at the FERC.

A2.7 The findings of both the FERC and state regulators are subject to review by the courts. Both regulators are treated as first level courts and appeals are taken to the next judicial level. In the case of the FERC, appeals are taken to the United States Circuit Court of Appeals.

DEVELOPMENT OF COMMON CARRIAGE

How The U.S. Got Where It Is Now

A3.1 Early in the 1980s, FERC embarked on a regulatory agenda that is described by some as a "non-regulatory" agenda to encourage freemarket competition in the natural gas supply market. This theme was initiated by passage of the Natural Gas Policy Act (NGPA) in 1978, first promoted at the FERC in a series of notes of proposed rulemaking (NOPR) by then Chairman Raymond O'Connor, that led to the issuance of Order No. 436. The freemarket theme was further accelerated, modified and interpreted in a series of FERC orders issued under the initiatives of current Chairwoman Martha Hesse.

A3.2 Despite the fact that this "freemarket" concept is ten years old, the natural gas industry finds itself in a market where the rules have not stood still since the issuance of Order No.436 in 1985. Every order of the Commission issued to date remains subject to court review or to an application for rehearing before the FERC. It is with this backdrop of orders, subsequently revised orders, and inordinately long delays in gaining regulatory approvals or interpretations that producers, pipelines and local distribution companies (LDCs) have had to attempt to conduct business. This has been especially difficult for LDCs because of the penchant of some state regulatory agencies to use retrospective prudency reviews of their gas supply decisions during this fluid market situation.

A3.3 A brief review of the significant actions that have shaped the natural gas industry environment that exists today in the U.S. should help establish a perspective on the current natural gas market situation.

A3.4 For most of the post WW II period, the price of natural gas at the wellhead was controlled by FERC at a level below freemarket prices, thus discouraging adequate exploration. Motivated by the natural gas shortages of 1976 to 1978 and brought about by a below-freemarket price of gas at the burner tip, Congress passed the NGPA in 1978; also a companion bill, the Power Plant and Industrial Fuel Use Act of 1978, to provide stimuli to a natural gas market that was assumed by most to be in the throes of an inevitable, long-term shortage.

A3.5 The NGPA provided for an almost immediate deregulation of "new" gas at the wellhead, but did not provide for the deregulation of "old" gas. The Act did, however, provide for price escalation of "old" gas to reflect general price inflation and authorised the FERC to raise the former ceiling prices to higher "just and reasonable" levels. (The FERC finally did this in 1986 in order No. 451.)

A3.6 As a result of those two laws:

- Only the price of "old" gas was controlled at existing levels;
- "New" gas was allowed to be priced at a much higher, "current" cost basis;
- The burning of gas was prohibited in new industrial and power plant boilers; and
- The finding costs of gas soared.

It was in this next period, with exploration increasing, gas prices now rising and demand still growing, that pipelines signed take-or-pay contracts. This would ultimately prove to be very costly, especially when the FERC issued Order No. 451 eliminating the ceiling price on old gas.

A3.7 The response of the market to the deregulated natural gas price was greater than anticipated. Supplies increased as did the price at the burner tip. Simultaneously, the price of oil began to drop and oil became very competitive. The resulting fuel switching (coupled with an economic downturn, especially in the large manufacturing sector of the U.S. "rust belt"[1]) caused significant losses of gas load. These losses, added to the growing gas supply, created the so-called gas "bubble". There are those in the natural gas industry who would prefer to call this excess supply the gas "sausage" due to its longer-than-anticipated life.

1/ The "rust belt" refers to areas of the U.S. where basic heavy industries (i.e., steel production) have experienced heavy recession.

A3.8 During this period, the FERC authorised limited period transportation service, under Section 311 of the NGPA, in order to enable pipelines to transport lower cost gas. (Order 500 provided that all NGPA 311 arrangements would end in October 1987.)

A3.9 A further significant move in response to the above-market price of pipeline companies' term contracts with LDCs was FERC Order 380 of May 1984. This relieved the LDCs of the variable cost related portion of their take-or-pay commitments to the pipelines and this paved the way for them to make increasing use of third party open access transportation to meet their gas requirements.

A3.10 The pipelines' response to the problem of lost sales to oil was to propose special marketing programs (SMPs). These programs offered low cost natural gas to directly served end users who were especially price sensitive. The FERC decided to allow the SMP programs.

A3.11 This decision was appealed to the United States Circuit Court of Appeals for the District of Columbia by the Maryland People's Counsel in 1985. The court ruled that the pipelines must offer SMPs to LDCs as well as to end-users, a course of action the pipelines could not afford. As a result of this finding, coupled with the market situation earlier-on described, the pipelines were forced to refuse to take high priced gas under take-or-pay contracts and instead purchased gas at lower cost on the spot market in order to remain competitive with oil at the burner tip.

A3.12 It is against this background that the FERC began to envisage a complete restructuring of the natural gas industry.

<u>Order No. 436</u>

A3.13 The essence of Order No. 436 is a separation or unbundling of the pipelines' traditional merchant function from that of transporters of third party gas. Briefly put, the Commission's support for Order No. 436 is as follows:

- Despite growth of a competitive wellhead market, the pipelines retained market power in gas transportation;
- Pipelines generally declined to transport gas in competition with their own sales;
- Pipelines discrimination in transportation has denied access to gas at the lowest reasonable rates.

It is apparently FERC's view that the separation of the two roles of pipelines would allow competition from many sellers to give consumers the benefits of deregulation at the wellhead.

A3.14 Again, briefly put, Order No. 436 provides for the following:

- Pipelines may take advantage of "blanket certification" of transportation services if they commit themselves to be an "open-access" pipeline (i.e., provide transportation service on a non-discriminatory basis);
- For open-access transportation, available capacity will be allocated on a "first-come, first-served" basis;
- Rate regulation for open-access transportation will take the form of ceilings and floor prices with the pipeline able to set prices within that band;
- Open-access pipelines must agree to allow their LDC customers to convert their contract demand from an obligation to purchase gas to an obligation to use transportation service, or to reduce their contract demand; and
- The FERC will issue expenditure certificates for new facilities where the pipeline undertakes the entire economic risk of the project.

A3.15 Virtually every sector of the industry challenged the Order No. 436 before the FERC and any court that would hear them, asserting a complete array of errors and omissions. The foregoing not withstanding, transportation was begun in earnest.

<u>Order No 451</u>

A3.16 On June 6, 1986, the FERC issued Order No. 451 as the next step in reordering the natural gas markets. The objectives of this order were to promote increased production of "flowing, old gas" (gas that was subject to the ceiling prices set by the NGPA and, therefore, lower priced); to discourage premature abandonment of existing old gas wells; and to lower the overall price of natural gas to consumers by placing flowing, old gas in competition with "new gas" supplies.

A3.17 To achieve these objectives, the FERC put into place four major regulatory changes, namely:

- The elimination of vintaging, and the establishment of a single incentive-based ceiling price for all old gas;
- The establishment of a good faith negotiation procedure whereby producers could get the new ceiling price for gas they commit to the interstate market;
- The creation of an automatic abandonment mechanism for the release of producers' interstate sales' obligations where the good faith negotiations did not yield an agreement;
- The establishment of blanket sales and transportation certificates to move the released gas if the negotiations fail.

A3.18 Again, these regulatory changes were challenged at the FERC and in the courts by every segment of the gas industry. The court challenges remain pending in the courts today.

Order No. 500

A3.19 After the U.S. Circuit Court of Appeals for the District of Columbia (the Court), in Associated Gas Distributors vs. FERC, remanded Order No.436 to the Commission because of the Contract Demand (CD) reduction provisions of that order, the FERC was unable to make the findings required by the Court to make subject provisions acceptable to the Court. Instead, the Commission elected to issue Order No. 500, which preserves the open and non-discriminatory transportation requirements of Order No. 436. This order also attempts to deal with the take-or-pay problems of pipelines that must transport gas in an increasingly competitive market.

A3.20 Briefly put, Order No. 500 provides for the following with respect to existing take-or-pay obligations:

- Pipelines will be allowed to recover between 25% and 50% of their buyout/down payments through a fixed charge to their customers as long as the pipeline agrees to absorb a like percentage of these costs.
- Pipelines may also recover up to 50% of their remaining costs through a commodity charge, a volumetric surcharge or some mix of both.
- The recovery spreads the charges over a large customer base, including interruptible sales, new transportation and small volume customers.
- Pipelines are permitted to file tariff rates for holding gas supplies for their customers to avoid future take-or-pay problems.

CURRENT SITUATION

General

A4.1 Common carriage is alive and well, despite the fact that the final rules under which the ultimate cost of transportation and related issues will emerge are not yet in place, and no one knows who will be the winners and losers in the economic game being played. The statistics for 1987 show that the major interstate natural gas pipelines transported 13.6 TCF for others, while making sales gas deliveries of 6.0 TCF.

A4.2 This large shift from sales service to transportation service has begun to make some impact on spot gas prices. Buyers are find a hardening of the market and a growing reluctance on the part of producers to discount prices. This has caused some electric generators to shift to oil. The cost of gas to end-users so far has tended to drop as lower gas costs have been passed on through purchased gas adjustment mechanisms.

A4.3 The structure of the natural gas industry, as outlined earlier in this Appendix, has not changed markedly. There has, however, been some fine tuning, as exemplified by the establishment of marketing affiliates/ subsidiaries to market gas to reduce take-or-pay obligations.

A4.4 Discounting has caused some to accept lower margins. However, the greatest potential impact on financial performance (take-or-pay obligations) is still waiting in the wings.

A4.5 Currently most, if not all, major interstate natural gas pipelines have either proposed or instituted Order No. 436 transportation programs, which include both firm and interruptible transportation. Certificates for transportation under Section 311 of the NGPA are no longer being issued. However, four out of the twenty-three major US pipelines have been permitted to continue to transport gas under Section 311 while their Order No. 436 proposals are pending. In May of this year the Commission approved the first gas inventory proposal under Order 500.

A4.6 As a part of its ongoing effort to get all the rules in place, the FERC, in June of this year, issued Order No. 497. This order established standards of conduct and reporting requirements intended to prevent preferential treatment of an affiliated marketer by an interstate pipeline in the provision of transportation service.

Structure and Level of Carriage Charges

A4.7 Interstate pipelines must use volumetric (per unit of gas moved) rates that reflect "material differences", in mileage or seasonal costs. However, in at least one case, the Commission has accepted "postage stamp" rates. Rates for firm transportation should cover the fully allocated cost of firm transportation, while rates for interruptible transportation should recover the short-term variable costs of interruptible service. Selective discounting is permitted.

A4.8 At this writing, very few of the major natural gas pipelines have filed Order No. 436 rates, even though providing transportation service under that order. So it is not yet clear what the level of transportation rates will be. If the Commission enforces its mileage-related concept, there will be considerable variances in the level of rates.

A4.9 One proposed form of transportation rates by a major pipeline is to charge a premium based on an index of spot prices with modifications based on gas takes.

Priorities

A4.10 The FERC has not yet sorted out the question of priorities as between pipeline customers and shippers.

Pipeline Capacity and Obligation to Serve

A4.11 The FERC has not made a definitive statement on this subject. It is an issue of great importance to LDCs because of their obligation to serve. However, the Commission has said that interruptible transportation must be carried out on a best efforts basis.

Importance of Traders

A4.12 As the use of transportation service has increased, it has become quite clear that the role of the broker seems, at this writing, to vary with the size of the entity wishing to transport. Large LDCs (gas and/or electric) and large industrial consumers have established natural gas purchasing units and do not make use of a broker. Small and medium size transporters depend upon brokers to arrange their spot purchases of gas. It is also likely that Cogenerators and Independent Power Producers will use brokers to purchase natural gas. The future role of the broker will most likely vary in importance with the degree of imbalance between supply and demand.

Imports

A4.13 With the exception of Canadian gas, imports do not play an important role in gas supplies. The Commission has approved imports from Canada after examining Canadian prices compared to U.S. prices and gas availability. There are currently several proposals before the Commission for the construction of pipeline capacity to bring Canadian gas into the Northeastern U.S. The Commission has been very slow in determining which proposal to certificate. All indications are that proposals to import Canadian gas will be given favourable treatment.

FUTURE PROSPECTS

A5.1 Future prospects for common carriage will depend upon the speed with which the freemarket created by the FERC reacts to changing conditions. The year 1987 continued the trend of reduced drilling activity from the record setting levels of the early 1980s, which means that reserves are not being adequately replaced. The AGA is now predicting that the gas bubble will disappear in 1990 or 1991. If the market place does not react quickly, demand could outstrip supply and prices will rise. On the other hand, with the price of oil falling to some $12 per barrel, industry and electric generators will burn oil instead of gas, which will reduce gas demand.

A5.2 If future FERC Commissioners continue the current Commission philosophy, common carriage is here to stay. This position will be supported by large users capable of fuel switching. The extent of future common carriage is problematical. As long as LDCs remain the largest component of the major interstate pipelines' throughput, the actions of state regulators could influence the extent of common carriage. This is because of the LDCs' obligation to serve. As supply and demand approach equilibrium and the spot market dries up, state regulators could begin to urge LDCs to return to gas purchasing on a long term firm contract basis to protect the interest of their firm customers. In any event, the LDCs will most likely maintain a degree of firm sales gas or firm gas purchased in the field and transported for them.

A5.3 The issue of bypass (i.e., end-users dropping off LDC systems and taking service directly from a pipeline) would also have an effect on the extent of common carriage.

A5.4 In the future, the FERC expects to introduce the concept of capacity brokering, the subject of a Notice of Proposed Rulemaking. The Commission proposes to begin experimenting with capacity brokering on a pipeline-by-pipeline basis. Another potential development would be to induce pipelines sized for sales loads, which might not have sufficient capacity for transportation, to invest in increased capacity. This, it has been (informally) proposed, would contribute to the overall efficiency of the natural gas industry.

APPENDIX B

GLOSSARY OF TERMS

GLOSSARY OF TERMS

Annual Contract Quantity (ACQ)	The target annual volume which a gas buyer and seller agree should be bought and sold under a gas purchase contract.
Auto-generation	Generation of electricity by an industrial concern on its own premises, using a purchased supply of another fuel such as gas, coal or HFO.
Back-up	An undertaking to make supplementary gas supplies available to a third party, in the event that the primary source fails to deliver.
Calorific Value (CV)	The amount of energy produced by combustion at specified conditions, per unit of gas volume (eg Kcal/m^3). CV can be quoted either net or gross and the gas industry normally uses the gross CV.
Capacity charge	A charge relating to the maximum use which is made of a facility, such as maximum pipeline throughput or gas offtake in m^3/hour or m^3/day.
Combined cycle power plant	Typically a gas-fired power station which combines a gas turbine with a steam turbine and boiler heated by the turbine exhaust gases, thus allowing electricity to be generated from two sources within the same plant.
Combined Heat and Power (CHP)	Use of fuel to produce heat and, at the same time, to generate electricity.
Commercial energy market	Comprises (inter alia) schools, hospitals, public buildings, offices, shops, hotels, etc.
Commodity charge	A charge for each unit of gas (volume or energy) which is consumed or transported.

Common carriage	A legal obligation on pipeline owners to provide transportation and related services for third parties.
Compressor station	A plant comprising gas turbines which are used to boost the operating pressure of a gas pipeline and thus increase throughput.
Contract sales	Gas supplied under the terms of an individual contract between a gas utility and the customer at an individually-negotiated price.
Direct firing	Process use of fuel, involving direct contact between the gas and the product.
Direct sales/ direct marketing	Sales of gas direct from a producer to an end-consumer, usually via common carriage.
Distribution system	Relatively small-diameter, low pressure pipelines used to carry gas from the transmission system to the consumer.
District Heating	Distribution of piped heat, usually in densely populated areas and often on the basis of CHP plants and/or local heating stations.
Dual firing capability	The ability of a consumer to burn two fuels in a particular plant (eg natural gas or fuel oil) and to switch between one and the other.
Feedstock	Raw material for manufacturing: used to describe the non-energy uses of natural gas for making ammonia and methanol.
FERC	The US Federal Energy Regulatory Commission.
Firm gas supply	A supply of gas which the seller is not permitted to interrupt.

"F" tariff	The lowest of the Dutch gas sales tariffs. This relates to feedstock use of gas by ammonia and methanol producers in the Netherlands and, like other Dutch industrial gas tariffs, is linked to the Rotterdam spot market price of low sulphur fuel oil.
Gas oil	A middle distillate product of crude oil refining. Relatively low in impurities and consistent in quality, it is an alternative to gas for domestic heating and for "premium" industrial applications, but not for feedstock uses such as ammonia manufacture.
Gas swaps	Usually bilateral agreements between gas utilities, whereby each party agrees to take physical delivery of gas contractually purchased by the other, often in order to minimise transmission costs.
Heavy fuel oil (HFO)	A residual "black oil" product of crude oil refining. Often contains impurities and is variable in quality, as for example between low (less than 1%) sulphur fuel oil (LSFO) and high sulphur (often over 3%) sulphur fuel oil (HSFO). It is a low grade fuel and competes with gas in "non-premium" industrial applications such as steam raising under boilers.
"H gas"	Higher calorific value gas of North Sea quality.
Industrial energy market	Comprises manufacturing, construction industries, mineral extraction and other industrial enterprises.
Interruptible gas supply	A supply of gas which the seller may interrupt on terms agreed in the contract.
"L gas"	Low calorific value gas of Groningen quality.

Liquefied Natural Gas (LNG)	Natural gas kept in liquefied form at very low temperatures. Sometimes used for long-distance transportation or for storage, because of the substantial reduction in volume when the gas is liquefied.
Liquefied Petroleum Gases (LPG)	Light petroleum products (propane and butane), mainly obtained from refining crude oil, although they are also present in small quantities in natural gas.
Load factor	Average consumption over a period expressed as a percentage of peak consumption during that period (typically, average daily consumption over a year as a percentage of the peak daily consumption in that year).
Looping	The construction of a parallel pipeline for part of an existing pipeline's length in order to increase transmission capacity.
Make-up	The right, following the payment of a take-or-pay penalty, to take an equivalent amount of gas free of charge (or receive a cash reimbursement, in some cases) under specified conditions in subsequent contract years.
Market-related pricing	A pricing policy which links gas prices to those of customers' alternative fuels. Strict thermal equivalent prices may be adjusted for the relative advantages of using gas and the alternative fuel in the equipment concerned (e.g. environmental cleanliness, in the case of gas vs HFO)
Minimum payment/ minimum bill	See "take-or-pay".
Natural gas	A gaseous mixture of hydrocarbons consisting primarily of methane.

Netback	Selling price less transport and other non-gas supply costs. In the gas industry, the netback at the border is frequently used to assess how much it is worth paying for additional gas supplies.
Non-premium	Low-grade, low-value fuels such as heavy fuel oil or coal; used to describe the market in which gas competes against such fuels.
Open access transportation	Voluntary transportation of gas for third parties on a non-discriminatory basis by US pipeline companies under FERC Orders 436 and 500.
Peak shaving	Facilities (such as LNG storage) designed to supplement gas supplies at times of peak demand only.
Price transparency	Usually used to refer to gas pricing systems which are based on clearly-defined rules (such as published tariffs or a published tariff formula) which allow consumers to identify the basis of pricing.
Premium	High-grade, high-value fuels such as gas oil or electricity; used to describe the market in which gas competes against such fuels.
Process use	Direct or indirect use of a fuel in industrial production processes, rather than for space or water heating.
Right of first refusal	An obligation on gas producers to offer their gas for sale to a specified buyer (gas utility). Only if the utility refuses to purchase at a reasonable price may the gas then be offered elsewhere and the seller may not accept a price from others which is lower than that which the utility is prepared to pay.

Ship-or-pay	An undertaking to pay for (at least) the transporation of a specified volume of gas, regardless of the actual volume shipped.
Shipper	Person seeking to have gas transported by a pipeline owner
Stand-by fuel	A stock of alternative fuel (usually HFO) retained by a non-premium gas customer for use in the event of interruption.
Steam raising	Production of steam in boilers for indirect process heat or space heating.
Swing factor	The inverse of the load factor, ie peak daily supply over annual average daily supply.
Take-or-pay	A contractual undertaking to pay for a specified quantity of gas, irrespective of whether that amount is consumed or not; sometimes referred to as a "minimum payment".
Tariff sales	Sales of gas made on the basis of a uniform tariff price, which is usually published.
Third party gas transportation	The transportation of gas by pipeline owners for third party shippers who retain title to the gas.
Transmission system	Large-diameter, high pressure pipelines used to carry large volumes of gas over long distances.
Wobbe number	A measure of the burning characteristics of a gas. For safety reasons, the Wobbe number must be within a certain range, especially where the gas is used in domestic appliances.

APPENDIX C

ACKNOWLEDGEMENTS

ACKNOWLEDGEMENTS

Although the views expressed in this report remain entirely the responsibility of the authors, we have benefited greatly from the opportunity to discuss the issues with a number of European gas industry organisations and other related bodies. In particular, we are very grateful to the following for their cooperation and assistance:-

Associated Gas Supplies Limited (United Kingdom)
AGIP (Italy)
Akzo (Netherlands)
Antwerpse Gasmaatschappij N.V. (Belgium)
BEB (West Germany)
BGE (Republic of Ireland)
British Gas plc
British Petroleum plc
Bundesverband der Gas and Wasserwirtschaft (BGW), West Germany
COMETEC-GAZ
Distrigaz (Belgium)
DONG/Dangas
Dow Europe
Enagas (Spain)
European Commission:
- DG III (internal market)
- DG IV (competition)
- DG XVII (energy)
Exxon Company, International
FIGAZ (Belgium)
Gaz de France
Greece: Prime Minister's Office
ICI
International Federation of International Energy Consumers (IFIEC)
Major Energy Users' Council (United Kingdom)
Mobil Corporation
Nederlandse Gasunie
Rhone Poulenc (France)

Ruhrgas (West Germany)
SEP (Netherlands)
Shell International
SNAM (Italy)
Societe Nationale Elf Aquitaine (France)
Thyssengas (West Germany)
UNIDEN (France)
VEGIN (Netherlands)
Vereinigte Elektrizitaetswerke Westfalen (VEW) AG, West Germany
Vereinigung Industrieller Kraftwirtschaft (VIK), West Germany
Verband Kommunaler Unternehmen (VKU), West Germany

APPENDIX D

TERMS OF REFERENCE

COMMISSION
OF THE
EUROPEAN COMMUNITIES

Directorate-General for Energy

Brussels, 2 May 1988
XVII-C-3
LB/ab

Annex

Study on the advantages and drawbacks for the European Community of the introduction of a system of "common carrier" for the transport of natural gas

1. *The aim of the contract is to decide the economic, legal and political implications of a modification in the conditions of natural gas transport in the EEC through the possible introduction of an obligation to transport for third parties on non- discriminatory conditions ("common carrier"). The study should take account of the characteristics of natural gas supply in the European Community as well as the Community energy objectives adopted by the Council in September 1986 (O.J.E.C. n° C 241, 25.9.86). These refer in particular to the necessity of greater integration of the internal energy market, free from all barriers, with a view to reducing costs and improving economic competitiveness, whilst maintaining security of supply.*

2. *With regard to "common carrier", the study should establish the existence of different legislative and regulatory situations as well as different administrative practices and their consequences (in the country and between countries).:*

   - *in the United Kingdom*
   - *in other Member States of the E.C.*

   The study should also determine under what conditions and to what extent a third-party transport obligation on non-discriminatory conditions could be introduced at E.C. level in the area of natural gas transport. The advantages and drawbacks of such a system should be spelled out:

   - *for the consumers*
   - *for the gas industry*
   - *for the Community, in relation to general economic considerations (including competition) and energy policy*

3. The contractor should work on the basis of regulations in force in the E.C. as regards the transport of natural gas. A summary of Member States' legislation in this field is av_ilable from the Gas Division in three languages (French, English, German).

The contractor should take account of the fact that the "common carrier" system which is applied in the U.S. for the transport of natural gas is situated within a very different economic framework than the one existing in the European Community. Indeed, contrary to the U.S. where the gas market is operated by many actors, the situation in the EEC is characterized notably by the existence of a limited number of suppliers and buyers.

The Gas Division can, in that respect, also provide related information, notably as regards the structure of the European gas industry, the natural gas supply outlook and the Community energy objectives.

Moreover, the position of COMETEC-GAZ, the European association for natural gas transport and distribution, on "common carrier" should be transmitted shortly to the E.C. Commission. This document will be available to the contractor once it is to hand.

Finally, the contractor will examine with the Gas Division the contacts to be made with certain key operators in the sector (two or three).

4. The study should be in the French or English language and should contain a summary of conclusions. The final report should be submitted to the Gas Division for acceptance. Twenty five (25) copies should be made available. The time allowed for completion is two and a half months following signature of the contract.

5. The offer should indicate the proposed work method as well as the situation of the study.