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Central Marine Research & Design Institute, Russia | The Fridtjof Nansen Institute, Norway | Ship & Ocean Foundation, Japan

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European Gas Markets and Russian LNG.
Prospects for the Development of European Gas Markets and Model Simulations of Possible New LNG Supplies from year 2000.

Tom Eldegard

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Title: **European Gas Markets and Russian LNG.**
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FOREWORD - INSROP WORKING PAPER

INSROP is a five-year multidisciplinary and multilateral research programme, the main phase of which commenced in June 1993. The three principal cooperating partners are **Central Marine Research & Design Institute (CNIIMF)**, St. Petersburg, Russia; **Ship and Ocean Foundation (SOF)**, Tokyo, Japan; and **Fridtjof Nansen Institute (FNI)**, Lysaker, Norway. The INSROP Secretariat is shared between CNIIMF and FNI and is located at FNI.

INSROP is split into four main projects: 1) Natural Conditions and Ice Navigation; 2) Environmental Factors; 3) Trade and Commercial Shipping Aspects of the NSR; and 4) Political, Legal and Strategic Factors. The aim of INSROP is to build up a knowledge base adequate to provide a foundation for long-term planning and decision-making by state agencies as well as private companies etc., for purposes of promoting rational decisionmaking concerning the use of the Northern Sea Route for transit and regional development.

INSROP is a direct result of the normalization of the international situation and the Murmansk initiatives of the former Soviet Union in 1987, when the readiness of the USSR to open the NSR for international shipping was officially declared. The Murmansk Initiatives enabled the continuation, expansion and intensification of traditional collaboration between the states in the Arctic, including safety and efficiency of shipping. Russia, being the successor state to the USSR, supports the Murmansk Initiatives. The initiatives stimulated contact and cooperation between CNIIMF and FNI in 1988 and resulted in a pilot study of the NSR in 1991. In 1992 SOF entered INSROP as a third partner on an equal basis with CNIIMF and FNI.

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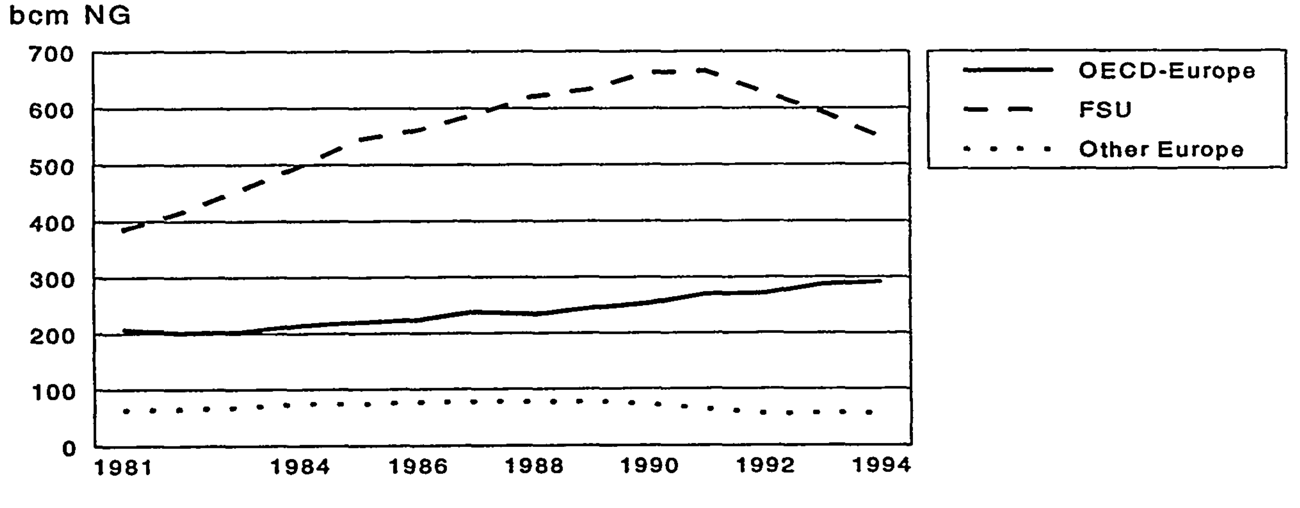
1. SUMMARY.

This study is part of the INSROP programme. It aims at clarifying the framework for possible LNG exports from Northern Russia, starting by the turn of the century. Focus is on the European natural gas markets and the study is developed in two stages. The first stage, covered by chapters 2 to 5, provides general background information on the market structure and related topics. In the second stage this information is used to develop a formal market model and subject it to simulations with various assumptions of the future gas supply. The model is described in chapter 6, which also provides results from the simulations.

Chapter 2 outlines facts and figures from the history of the European natural gas market development. Regarding consumption, the figures reveal substantial regional differences. As illustrated in Figure 1.1, gas consumption in European OECD countries exhibits steady growth since the early eighties. In Eastern Europe and the FSU (Former Soviet Union) a similar growth pattern during the early eighties was disrupted by the political and economic turmoil that emerged towards the end of the last decade. The trend shift is particularly pronounced in FSU where gas consumption has plunged after 1991. Still there are no indications that this decline will come to a halt within the next few years.

A large number of European countries have domestic gas production, but the reserves are unequally distributed. Close to ¾ of non-FSU reserves are located in Norway, Holland and UK. Thus, most European countries are net importers of natural gas. Among the OECD members only Norway and Holland are major net exporters. In 1994 these two countries covered about 1/3 of total European gas imports (according to BP) with the remainder split between FSU (50% of total imports) and Algeria (14.4%).



Source: BP Statistical Review of World Energy

Figure 1.1 Natural gas consumption in Europe and FSU - 1981 to 1994.

Chapter 3 addresses the underlying conditions for the development of natural gas markets in Europe. The discussion is organised around five main points of which the first one relates to the geography of supply. Due to the lack of adequate infrastructure, vicinity to source was of particular importance in the early phase of market development. At this time natural gas consumption expanded locally from fairly limited-sized, domestic production fields, and the petroleum gas took a position more as a complement than a real substitute to traditional town gas. Following the 1958 discovery of the Dutch Groningen field the situation started to change. This new field offered the opportunity for low cost supply of vast gas volumes to some of the most densely populated areas in Europe. Holland adopted a policy of aggressive gas marketing and thus nurtured a rapid growth in natural gas consumption in Holland as well as in the neighbouring countries.

A new milestone in the history of European gas markets was laid in the early 1970's when gas commenced to flow from the distant and substantially more expensive developments outside Europe (i.e. in West Siberia and Algeria) and in the North Sea. About the same time, the 1973 oil price shock strongly improved the competitive position of natural gas and also focused attention on energy balances and the security of energy supply. Benefiting from these new settings, gas sales strategies were modified and oil price parity became the predominant principle for stating the price in new gas sales contracts. Price parity is still a prevailing contract principle, but the reference point has been broadened. The gas price is now more frequently related either to a certain bundle of energy products or to the price of the most adequate substitute for the specific buyer.

The oil price shocks in the seventies initiated a fundamental reconsideration of the energy situation in most European countries. New policies were developed to diversify energy consumption and to reduce dependency on imported oil. Much attention was directed toward nuclear power technology. Several countries also launched ambitious programmes to stimulate domestic coal industries; a strategy that frequently was mingled with measures intended to counter unemployment and growing regional dissimilarities. The focus of attention is clearly demonstrated in OECD (1991) figures on the funding for energy research in IEA countries. During the years from 1988 to 1990 nearly ¾ of total public funding was allocated to nuclear technology and coal. This active stimulation of atomic power and the coal industry has obviously encumbered the development of natural gas, particularly in the power sector.

The Commission of the European Union has for several years been eagerly promoting trade liberalisation in the energy sector. Nevertheless the introduction of a common European gas market still lacks the approval of the member states. The current situation, characterised by strong segmentation and national import- and transmission monopolies, is likely to prevail, at least till after the turn of the century. Despite a clear trend to liberalise gas trade at national levels[1], most countries still resist a freer gas trade across the borders.

A substantial number of new infrastructure developments for natural gas are either underway or planned. Several of these projects take place in Central Europe in order to increase the internal throughput capacity, particularly in Germany. In addition, the major gas suppliers are

[1] E.g. the introduction of TPA (third part access) in UK, aggressive Wingas marketing in Germany and the privatisation of ENI in Italy.

increasing export capacities to a degree that may significantly alter the market balance in the near future. Important projects are:

- A new major pipeline complex from FSU via Poland to Germany with a projected maximum annual capacity of 65 bcm (billion cubic meters) to be reached in 2005.
- Several new pipelines from Norway to the continent, raising annual capacity with 40 - 50 bcm within 2005.
- Construction of the "Interconnector", a pipeline with an annual capacity of 20 (10) bcm from UK to the continent with flow start scheduled before the turn of the century.
- A new pipeline from Algeria that splits in a Moroccan and a European branch, the latter entering Europe in Spain after crossing the Strait of Gibraltar. Annual capacity is planned at 15 bcm and flow start scheduled for 1997.

To position gas in a global perspective, chapter 4 makes a swift visit to the regional gas markets in North America and Far East Asia. The former, which includes USA, Canada and Mexico, is the oldest of the three major regional gas markets world-wide. Since the late seventies, this regional system has undergone fundamental reforms, including trade liberalisation and introduction of common carriage in gas transportation in USA. Quite different from the history of natural gas in Europe and North America, the regional gas market in Far East Asia has not grown out from local, low cost gas occurrences. In this region it has already from the start been necessary to overcome substantial and cost-incurring distances between producers and consumers. The former are basically located on "islands" in Southern Asia (including Australia) and in the Middle East, while the gas purchasing countries, primarily Japan and more recently also South Korea and Taiwan, lie further to the North east. Currently practically all internationally traded gas in this region is shipped as LNG.

Chapter 5 assesses the cost structure of the LNG chain. A brief introduction to the basic cost considerations is supplied with some available information on investment costs and average unit costs in liquefaction, shipments and regasification. The chapter also gives an overview of existing LNG export capacities world-wide and major reception terminals in Europe and USA. LNG contract prices are cited from BP (Review of World Gas *1995*).

The second stage of this study, depicted in chapter 6, employs a scenario analysis to evaluate the economic effects of hypothetical LNG deliveries from northern Russia. The work is carried out on a model named GAS, that is especially developed for the analysis of West European natural gas markets. The model is designed to allow users to create a structural system of interconnected producers and market regions. Every defined connection line between separate "agents" in the model is assigned a maximum transport capacity and a fixed unit tariff. Furthermore, the user may equip every producer with one or several gas fields, each with a unique cost structure. A specifically designed calibration procedure is used to establish basic demand relations from historic data on every market region. In addition the model user controls a set of growth parameters, which may also strongly influence demand at calculation time. A solving routine attached to the model looks for a general equilibrium solution that can satisfy the sum of specifications set up by the user.

The first step in the analysis was to develop a set of basic assumptions for the evolution of European natural gas markets till 2005. After having fixed model parameters according to the assumptions, a base case scenario was calculated for the years 2000 (BASE20) and 2005 (BASE25). This scenario was subsequently used as a point of reference for the alternative "Insrop" LNG scenarios that were considered. Both started with a 10 BCM capacity in 2000 and assume that all deliveries will be landed in northern parts of Europe (i.e. north of Spain). The first alternative anticipates that the 10 BCM capacity is continued till 2005 (SMALL). The second alternative evaluates the consequences of a further expansion to 30 BCM capacity in 2005 (LARGE). Figure 1.2 illustrates the effects of the Insrop scenarios on the contribution from gas sales to four of the major producers. FSU (Russia) is here presented both "alone" and with "Insrop" LNG included.

According to the analysis carried out in this study the introduction of a new LNG supplier in the European gas market will inflict a substantial loss upon all the existing producers. Even though the hypothetical LNG supplier may run an isolated surplus, the combined business of FSU and Insrop will lose compared to the FSU alone. The reason is that the resulting drop in prices, more than outweighs the expansion in the combined FSU-Insrop sales. The primary keys to this result are the assumptions made for gas demand and supply capacity. Thus, the LNG alternative will find it hard to get approval for purely economic reasons as long as the Russians maintain sufficient pipeline export capacity at the current cost level. What may possibly modify this conclusion is if either LNG is selected as export solution for associated gas from isolated oil field developments, or if domestic Russian gas demand grows significantly faster than anticipated.

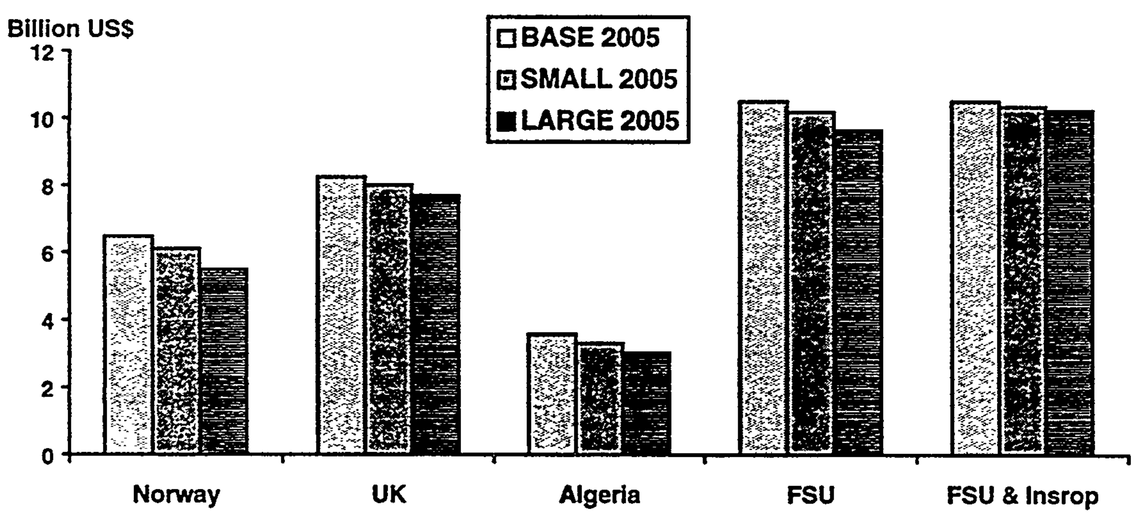


Figure 1.2 Altered Contribution from Gas Sales with 'Insrop' LNG.

2. NATURAL GAS IN EUROPE - A BRIEF HISTORY.

The main purpose of this chapter is to supply the reader with an overview of some facts and figures concerning the development of natural gas markets in Europe. The first part considers the history of gas consumption, while the latter assesses the sources of supply.

2.1 The consumption of natural gas.

Consumption of natural gas is far from equally distributed among the European countries. The national markets have also followed widely different paths of development. This applies not only to the speed of market growth, but to the distribution among various fields of application as well. Explanations may be found on many levels. In addition to variations in the availability of gas, the differences can also be attributed to specific national industrial policies and energy policies in particular. Also to be noticed is the obvious link between national resource base and the level and direction of public engagement in the energy sector. Such engagements have been supported in many ways; through direct public ownership, by market regulations and also more indirectly through the configuration of tax regimes and subsidies.

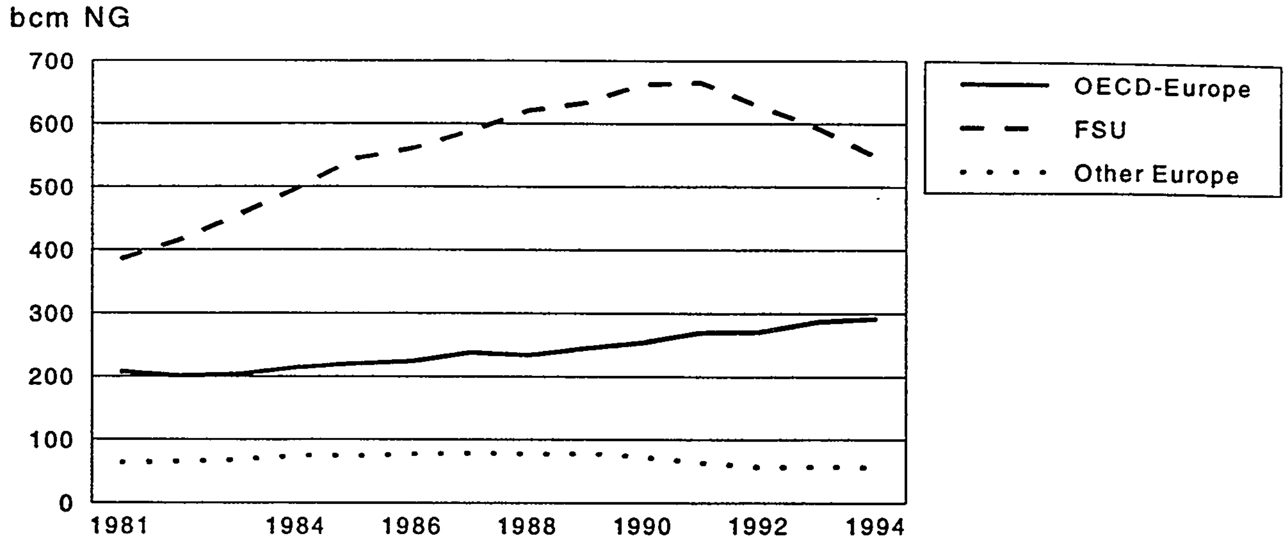
2.1.1 Regional development in natural gas consumption.

Looking at different parts of Europe, the development in natural gas consumption has been very heterogeneous. This is well demonstrated within the framework of three market regions: Western Europe (OECD-Europe), Former Soviet Union (FSU) and Other Europe. The last region mostly comprises non-FSU countries in Eastern Europe. Figure 2.1 displays the development for each of these regions from 1981 to 1994. Table 2.1 also gives some figures for selected years.

In OECD-Europe the natural gas consumption has been increasing during most of the period. Only for two years, 1982 and 1988, do the BP figures show a decrease from the preceding year. In 1982 the consumption declined about 3 per cent and in 1988 by 1.8 per cent. In 1988 the decrease most probably resulted from casual climatic variations. The 1982-setback had more profound reasons, and despite a significant rise in 1983 the 1981 consumption was not exceeded until 1984. The setback was due to a general deterioration in World economy and followed in the wake of the Iraq-Iranian war that broke out at the end of 1978. When the Iranian Gulf became part of the combat area the oil exports from OPEC fell significantly, causing a sharp rise in oil price. From 1978 to the top level in 1981, the oil price more than doubled in real terms. OECD-Europe was strongly hit by this price shock and the value of industrial production decreased both in 1981 and 1982[2].

Looking back at the first oil crisis in 1973, the succeeding period may be split into three separate segments of time. During the first six years - until 1978 - the natural gas consumption in OECD-Europe increased rapidly, showing an average annual growth rate of 4.5 per cent.

[2] From 1980 to 1982 the OECD-index of industrial production for the area, fell back from 96.6 to 93.4 (base year 1985). For the five-year period from 1979 to 1984 this index showed an increase of only 0.3 percent.



Source: BP Statistical Review of World Energy

Figure 2.1 Natural gas consumption in Europe - 1981 to 1994.

MARKET REGION	Natural gas consumption million tonnes of oil equivalent			Share of natural gas in primary energy %			% change in NG consumption 1981-1994	
	1981	1988	1994	1981	1988	1994	Total	Yearly
Western Europe	186.9	210.6	263.2	15.2	15.5	18.4	40.8	2.67
Former Soviet Union	346.7	558.6	493.5	30.5	40.6	49.3	42.3	2.75
Other Eastern Europe	57.9	70.0	51.0	16.6	18.0	19	-11.9	-0.97
Total World	1315.7	1660.5	1824.2	20.5	21.9	23	38.6	2.55
Austria	3.9	4.4	5.8	19.1	21.1	25.3	48.7	3.1
Belgium & Luxembourg	9.5	8.4	10.1	19.8	16.2	18.3	6.3	0.5
Denmark, Finland & Sweden	0.6	3.4	5.9	0.8	4.2	6.8	883.3	19.2
France	24.5	23.6	27.7	13.9	11.5	11.9	13.1	1.0
Germany	49.4	52.3	61.1	14.6	14.7	18.3	23.7	1.7
Italy	22.8	34.1	40.9	16.7	23.6	27.2	79.4	4.6
Netherlands	30.0	30.6	34.2	42.4	41.2	42.6	14	1.0
Spain	2.1	3.5	6.5	2.9	4.4	6.9	209.5	9.1
United Kingdom	42.4	46.4	60.9	21.7	22	28	43.6	2.8
Czech Rep. & Slovakia	7.3	8.5	10.2	10.2	11.2	17.7	39.7	2.6
Hungary	7.8	8.8	8.0	29	30.7	33.9	2.6	0.2
Poland	8.3	9.7	8.2	7.5	7.4	8.7	-1.2	-0.1

Source: BP Statistical Review of World Energy

Table 2.1 Natural gas consumption - energy shares and growth.

From 1978 to 1982 the annual growth rate fell to only 0.35 per cent. From 1983 on, the natural gas consumption regained a high expansion rate. Average annual growth rate from 1983 to 1994 was 3.3 per cent and the first half of the nineties showed an annual growth rate of 3.6 per cent.

In FSU the responses to the oil crises were very different from those that appeared in Western Europe. Here the natural gas consumption increased quite slowly, by an annual rate of about a half percentage, from 1973 to 1978. Then started a period of fast growth that lasted till 1990. The annual increases were particularly high from 1978 to 1982, showing an average growth rate of 14.8 per cent. From 1982 till 1990 the consumption grew by an annual rate of 6 per cent. The top level was reach in 1991 when FSU consumed 665.5 BCM - nearly 2.5 times the consumption in OECD-Europe this year. Thereafter the consumption has declined rapidly, and in 1994 it was back down at the level of 1985.

Much of the difference between FSU and Western Europe may be explained by a look at the regional resource situation. The petroleum deposits on own territory are much larger in FSU than in Western Europe. Profiting from its vast resources the FSU expanded its natural gas sector at an early stage, and domestic consumption had already reached a substantial level at the time of the first oil crisis[3]. In 1978 natural gas covered more than 29 per cent of primary energy consumption in FSU. This is compared to about 12 per cent in Western Europe and slightly above 18.5 per cent worldwide.

As FSU was completely self-sufficient with petroleum, the country was not hit in the same way by the oil price shocks. Peaking oil prices even increased FSU incomes from oil exports and gave an extra inflow of hard foreign exchange that was very welcome. Partly to protect oil exports from growing inland demand, a gigantic development program for natural gas was initiated in the mid-seventies. The first measurable results of these programs coincided with the second oil crisis in 1978 and gave start to the 12 year long period of rapidly expanding natural gas consumption that followed.

Since the split up of the Soviet Union in august 1991, the whole area has been beset with severe economic problems. The switch over from centrally planned to market economy has not been easy, and the necessary adaptations are still far from completed. In 1992 and 1993 the gross domestic product in Russia is reported to have declined by 19 and 12 per cent respectively (CIA, 1994), and in 1993 the industrial production fell by 16 per cent. Against this background the 17.6 percent decline in natural gas consumption from 1991 to 1994 is not surprising. The dramatic declines in demand and production are spectacular symptoms of fundamental and severe problems in the organisation of production and external trade relations, particularly with the former member states of the union. Along with other industry, the natural gas sector is suffering from the overall drainage of funding for maintenance and investment programs.

The development in the *Other Europe* region, which mainly includes former East bloc countries, has of course been strongly connected to the history of the FSU. This is particularly apparent for the period from mid-eighties when the disintegration started. In the first years after 1973, the market for natural gas in *Other Europe* developed more independently, mainly on the basis of local resources. In 1973 the imports covered only 15.2 per cent of a 38.5 BCM

[3] FSU natural gas consumption was 233 bcm in 1973, according to BP Gas Review, *1994*

total consumption. This gradually changed as imports from the FSU increased and peaked with an import share of close to 55 per cent in 1990.

From 1973 to 1978 consumption of natural gas in *Other Europe* increased at an average annual rate of nearly 8 per cent. Then the growth speed was dampened a little, but still continued at annual expansion rates above 4 per cent until 1986. Except for a temporary drop in 1988, regional consumption levelled out at about 80 BCM from 1986 to 1989. Then followed three successive years of sharp drop in natural gas consumption - down to a level of about 60 BCM, which has been maintained since then.

2.1.2 End use and share of gas in total energy.

Table 2.1 shows the share of natural gas in total primary energy for a number of European countries and for several regional aggregates, including figures for the entire World. Starting with Western Europe, we see that the relative position of natural gas improved only slightly from 1981 to 1988, despite a significant growth in consumption (1.7% average annual growth). During this period natural gas stagnated in the most developed markets in northern Continental Europe, particularly in Holland, Belgium and France. In the two latter, gas consumption even declined. This may partly be attributed to capacity constraints in supply, but the energy sector was also influenced by the fast expansion in French nuclear electricity. Contrary to this trend, gas consumption grew at a rapid rate in the southern countries, Italy and Spain, and in the young Scandinavian market.

From 1988 to 1994 West European natural gas consumption grew considerably faster than total energy. The average annual growth rate was 3.8 per cent compared to only 0.9 per cent for primary energy. Thus the share of natural gas in total energy consumption increased by nearly 3 per cent, from 15.5 to 18.4 per cent. During this period natural gas improved its relative position in all the countries, but the improvement was still very small in France.

The countries with the highest natural gas share in 1994 were Holland (42.6%), United Kingdom (28%), Italy (27.2%) and Austria (25.3%). In Holland the share has remained fairly constant since 1981, but in the other countries the gas share has risen substantially, particularly since 1988. Both in UK and Italy much of the growth is due to increased use of gas in electricity generation, a development that is expected to continue. The potential for natural gas in the electricity sector is large in many other countries as well, but in several of these, a release of the potentials will require a significant shift in national energy policies (particularly in France and Germany). Attempts to reach national targets for reduced emissions of greenhouse gases will stimulate policy changes, while sectional interests may work in the opposite direction.

To illustrate the volume consequences of increasing the share of natural gas in primary energy in Western European, assume the gas share rises to 21 per cent in 2000 and further to 25 per cent in 2005. This scenario is not impossible. Even with no growth in total energy consumption it would imply increases in natural gas demand of 37 BCM by 2000 and 94 BCM by 2005. With annual growth rates for primary energy in the range from 0.5 to 1.5 percent, the gas demand would be up 46 - 65 BCM by 2000 and 114 - 158 BCM by 2005.

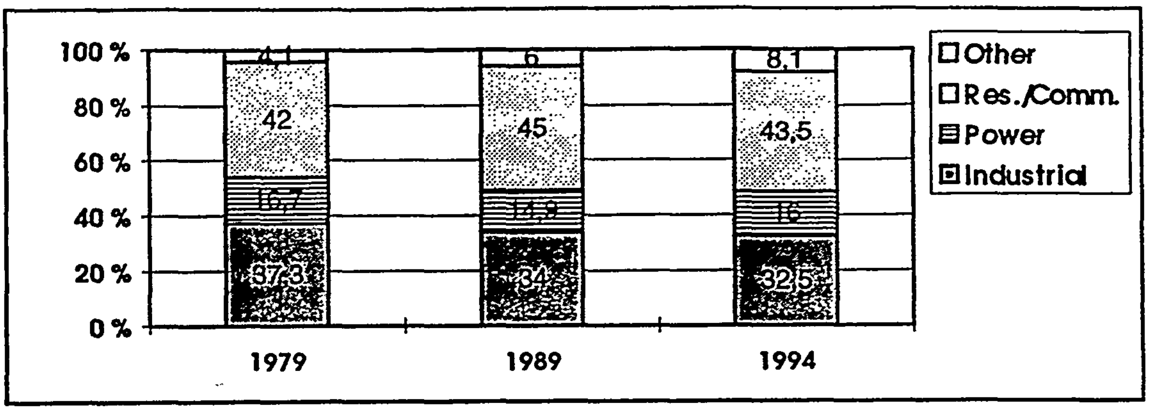


Figure 2.2 End use of natural gas in OECD-Europe.

Figure 2.2 displays the distribution of natural gas consumption among 3 categories of end use applications in OECD Europe[4]. It appears from the figure that the composition of natural gas consumption has not changed dramatically since 1979. Excluding the '*other*' category we see that the share of industry has dropped around 3.5 percent, while residential/commercial gas usage has increased equally. The 1993 share of gas used for electricity generation was unchanged from 1979 - at 17.4% of registered end use - but this share dipped in the meantime and in 1989 was down at 15.9 percent. The gas share in electricity generation in OECD Europe is below average for the organisation. In 1992 6.5 percent of European electricity was produced from natural gas compared to 13 percent in USA and 18.1 percent for Pacific OECD members (IEA, 1994a). Among the major countries the gas share in electricity production was particularly low in France (0.65%) and UK (2.68%). On the other hand Holland produced 56.2 percent of its electricity from natural gas in 1992, with Italy coming next at 15.8%.

In non-FSU countries in the former East-bloc the situation differs considerably between north and south. The northern countries, Poland, Czech Republic, Slovakia and Hungary, appear to have advanced further in the process of transition to market economy than have their former allies, such as Bulgaria and Romania. The market orientation in the north is also likely to influence the price regime for natural gas and will probably improve the position of gas in competition with coal in particular, but perhaps also towards oil. However, official energy authorities in Poland and the Czech Republic still expect the development in gas consumption to follow relatively close to the development in total energy. But this view is strongly opposed by independent analysts. Cofala (1994) for instance, asserts that authorities tend to exaggerate the development in total energy and strongly underestimate the potential for natural gas to substitute coal. His view is that reduced energy intensity - resulting from increased efficiency and shut downs in heavy industry - will entail stagnation in total energy consumption despite an anticipated high economic growth rate. Gas consumption is expected to continue to grow, primarily at the expense of coal. A tendency to an expanding gas share is also evident from table 2.1. Even though gas consumption dropped significantly in Hungary and Poland from 1988 to 1994, the share of gas in primary energy increased markedly during the same period.

[4] The '*other*' category covers statistical differences, own use by gas transmission companies etc.

2.2 Natural gas supply to the European market.

The scenario analysis in chapter 5 will distinguish between production and consumer regions. The base case includes 13 market regions and 5 producers. Two of the producers, UK and Holland, are also represented as separate market regions. The three others, Norway, Algeria and FSU are treated solely as producers. This implies that the FSU domestic consumption is excluded from the model, so that only the net exports to rest of Europe are considered. The setting for the scenario analysis explains the special organisation of table 2.2 and table 2.3 below.

2.2.1 Major European gas producers.

From table 2.2 it appears that national levels of proven natural gas reserves in Continental Europe, except Holland, are rather limited. Close to 74 percent of known 'internal' European reserves are located in Holland, UK and Norway. The remaining 26 percent are divided 55/45 between OECD countries and former East bloc countries. Based on acknowledged reserve estimates (BP Energy Rev, 1995), current European consumption level at 347 BCM may theoretically be fully supplied from 'internal' production for another 17.7 years. If Norway is excluded the R/P ratio falls to 11.9 years.

In Northern Continental Europe Holland has taken a special role as a swing producer. The country contracts its gas activities during the warm season and expands production and exports in winter time when gas demand is high and the supply from more distant producers is likely to be constrained by pipeline capacities. Holland has implemented a system of regulations and tax mechanisms to force domestic producers to install and sustain swing capacity. Through this policy Holland has been able to collect a price premium on gas exports. On the other hand there are also costs involved in maintaining spare capacity during a large part of the year.

Production in Holland is likely to remain at the current level as the country has decided not to expand its gas exports. This line appears to have broad support at the political level. It aims partly at maintaining national control over the dominant source of domestic energy supply. Another objective in Holland is to avoid a too strong dependence on incomes from gas exports, and thus reduce the economic exposure to gas price fluctuations. Also important is the special topography of Holland with vast land areas located below sea level. When subsidence was observed at the Norwegian Ekofisk field in the North Sea, it thus raised serious questions regarding the consequences of a continued rapid depletion of the inland Groeningen field.

UK production and consumption has increased sharply during the last years. So far nearly all domestic production has been consumed inland and in addition the UK market has been supplied from Norway[5] . The recent expansion in domestic production has for the moment made Norwegian gas obsolete, and several British production companies are now eager to start exports to the continent. Physically this will be possible when the 20 BCM Interconnector

[5] Limited amounts of gas have been exported to Germany and Holland through small capacity pipeline connections between fields in the Southern North Sea. In 1994 this export amounted to 0.9 BCM.

becomes operative. However, considering the current market conditions on the continent, the UK capacity to become a significant gas exporter is questioned by analysts (Wood Mackenzie, April 1995). Firstly, the broadly accepted UK reserves are not large enough to guarantee long term security of supply. Secondly, for the next decade much of the anticipated increase in gas consumption in North West Europe is already covered by contracts. Unless an extensive market reform is carried out very soon in Continental Europe, the market available

	Reserves BCM	Production BCM 1994	R/P-ratio	Comments
'Gas consumers':				
Scandinavia	121	4.6	26.3	- Only Denmark
France	36	3.2	11.3	
Germany	303	15.6	19.4	
Austria	22	1.2	18.3	
Poland	155	3.4	45.6	
Czech Rep. and Slovakia	13	0.3	43.3	
Central & Southern Europe	554	24.1	23.0	
Italy	374	20.1	18.6	
Spain and Portugal	19	0.8	23.8	
TOTAL	**1 611**	**75.2**	**21.4**	
'OECD producers':				
United Kingdom	630	65.4	9.6	
Holland	1 875	65.9	28.5	- IEA reports prod. at 88.2 BCM!!
Norway	2 008	30.6	65.6	
TOTAL	**4 513**	**160.9**	**27.9**	
FSU production:				
Russia	48 138	566.2	85.0	
Turkmenistan	2 859	33.2	86.1	
Uzbekistan	1 869	44.0	42.5	
Kazakhstan	1 841	4.2	438.3	
Ukraine	1 133	17.0	66.6	
TOTAL	**55 982**	**670.9**	**83.4**	
Africa:				
Algeria	3 625	50.4	72	
Libya	1 297	6.2	209	
Nigeria	3 398	4.1	829	- Planned LNG exports to Europe / North America
TOTAL	**8 320**	**60.7**	**137**	
Middle East:				
Iran	21 000	31.1	675	- Iran may theoretically ship gas to Europe through existing pipeline connection to the FSU network
Qatar	7 079	12.9	549	
UAE	5 794	24.5	237	
Saudi Arabia	5 264	37.7	140	
Iraq	3 100	3.0	1033	
Other	2 907	18.2	160	
TOTAL	**45 144**	**127.4**	**354**	

Source: BP Statistical Review of World Gas *1995*

NB! European 'consumers' are organised according to the groupings used in the succeeding scenario analysis.

Table 2.2 Natural gas reserves and production with particular relevance to Europe.

IMPORTER	EXPORTER UK	Holland	Norway	Algeria Pipe	LNG	Total	FSU	TOTAL
Scandinavia							3.2	3.2
UK			3.1					3.1
Holland	0.3		2.8					3.1
Belg. & Lux.		5.9	2.6		4.0	4.0		12.5
France		5.1	6.9		7.7	7.7	11.3	30.9
Germany & Switz. [1]	0.6	25.1	9.9				28.0	64.5
Austria [2]			0.3				4.4	4.9
Poland							5.8	5.8
Czech & Slovak							12.9	12.9
Centr. South Europe				0.3	0.4	0.7	20.3	21.0
Italy		4.5		11.5	0.1	11.7	12.9	29.0
Spain/Port. [3]			1.0		4.6	4.6		7.4
TOTAL	0.9	40.5	26.6	11.8	16.7	28.5	98.7	198.3

Source: BP Review of World Gas *1995*
Notes:
[1] Additional German imports of 0.9 BCM from Denmark included in total. Total Swiss import was 2.2 BCM of which 1.3 BCM originated from Germany. The remainder came from Holland (0.6BCM) and FSU (0.4 BCM)
[2] Additional imports from Germany (0.3 BCM) included in total.
[3] Currently only Spain consumes gas. Additional LNG from Libya (1.4 BCM) and Australia (0.5 BCM) included in total

Table 2.3 Regional trade balance for natural gas in Europe 1994.

for UK gas exports will most likely be small and low price. The primary function of the Interconnector may thus become to serve as a gas price equaliser in a gas spot market which is rather small, particularly on the Continental side. Capacity utilisation will then be fairly limited and with gas flowing in both directions.

Norway is the European country with the largest commercial natural gas reserves according to BP. During the last decade annual production has moved in the interval from 25 to 30 BCM. Close to 100 percent of production is exported. Destinations of exports have gradually been shifted away from UK to Continental Europe. Further exports to UK are currently constrained by a deadlocked disagreement on tariffs and transport conditions for the Frigg transport system. The Norwegian part of the system is currently running at less than 30 per cent capacity utilisation.

Exports to the continent are on the other hand set to rise sharply over the next decade as several new high capacity trunk lines will become operative. So far Norway has contracted deals and options for annual deliveries of more than 60 BCM after 2005, and substantial additional deliveries are being negotiated. The requests with the largest volume potentials are

	EXPORTER							
				Algeria				
IMPORTER	UK	Holland	Norway	Pipe	LNG	Total	FSU	TOTAL
Scandinavia							3.2	3.2
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2.2.2 Domestic production and gas supply in other European countries.

In Scandinavia exclusive Norway, the natural gas market is developing in two segregated units. In the East, Finland has increased its annual gas consumption from less than one to around 3 BCM over the last decade. This consumption is completely based on Russian imports. The other part of the Scandinavian market is branching out from Denmark. Production from the offshore based Danish gas reserves commenced in 1984 and reached 4.6 BCM in 1994. The production is feeding a growing domestic consumption, which in 1994 was 2.75 BCM, and the surplus is exported to Sweden and Germany.

Danish gas production will increase further during the next years, to at least 7.4 BCM, which is the contracted plateau level for production from 1997 (Wood Mackenzie, June 1995). According to recent forecasts this production will still not be large enough to cover gas demand at the turn of the century, which is estimated at 9.5 BCM. Several alternatives exist for filling the gap. The most likely solution appears to be imports from Norway, either by a dedicated pipeline from Norwegian North Sea installations or through the existing connections to the Emden terminal.

Contrary to Denmark, Germany has no offshore gas production. The onshore reserves have been depleted since the 1930s. Output peaked at an annual level slightly above 20 BCM in the late 1970s. During the 1980s' production decreased to an annual level of about 15 BCM, and there are no indications that this level will change significantly in the near future. Reported reserves are theoretically sufficient to sustain the current production level for another 15 years. Production will most likely start declining from about 2000.

Domestic German production covered only 17.6 per cent of total net supply in 1994. Thus, more than 80 per cent of the natural gas consumed was imported. The major external suppliers were FSU, with 44 % of imports, Holland with 39 % and Norway with 15 %. In addition Germany imported around 1.5 BCM of gas from Denmark and UK. The already strong import dependency is expected to increase due to a continued growth in gas consumption. The Troll contracts with Norway will substantially raise the Norwegian share in imports for the near future. In a longer perspective the composition of imports is more unpredictable. Ruhrgas, the major transmission company, is at the moment strongly associated with Norway, but meets increasing competition from Wintershall. Through the Wingas joint venture with Gazprom, Wintershall promotes Russian gas. The Russian supply capacity to the German border is expected to rise sharply when the planned trunk line through Poland becomes operative.

In north west Europe all gas to the Belgian-Luxembourg market region is imported, while France has a small but declining domestic production. In Belgium and Luxembourg the gas arrives either by pipeline from Holland and Norway, or is shipped in as LNG from Algeria.

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[6] According to DN Italy and Spain have made requests for annual deliveries of 6 and 4 BCM respectively from 2000)

Supply capacity to this region will increase sharply till 1997. By that time the Interconnector to UK is scheduled to be on line and the Zeepipe system from Norway will have reached its full capacity.

France is currently importing more than 90 per cent of its gas consumption and the import dependency is expected to rise further. In 1994 the external gas was supplied from Holland (16.5%), Norway (22.3%), FSU (36.6%) and Algeria (24.9%), the latter beeing shipped in as LNG.

The natural gas market at the Iberian Peninsula is expanding rapidly. So far only Spain consumes natural gas, but Portugal is expected to start gas distribution in the near future. Domestic production is small. In 1994 the bulk of supply arrived as LNG from Algeria (4.6 BCM) and Libya (1.4 BCM). In addition a delivery of 1 BCM from Norway was piped down through France. In a few years the construction of a large scale trunk line from Algeria - via Morocco and Gibraltar - is expected to substantially improve the supply situation.

Italy is expanding offshore production with economic support from EU funds. The country has a significant domestic resource base, particularly offshore. In last year's issue of the BP Gas Review the estimates of proven reserves were upgraded from 302 to 374 BCM, due to intensified exploration activities. However, the national production and resources are far from sufficient to feed the growing consumption in a longer perspective. Diversification of supply appears to be a predominant aim of the production strategy. In 1994 more than half the Italian gas consumption was covered by imports from Russia and Algeria. By expanding own production, Italy may moderate a growing import dependency as gas consumption is expected to increase substantially during the following years, particularly in power generation (OGJ, 13.03 1995). Increased domestic production will also give more time to develop import capacities and hopefully to further diversify external sources of supply. Negotiations with Norway failed some years ago over possible LNG deliveries from fields in the Barents Sea. Renewed contacts concerning pipeline deliveries are now more likely to succeed. LNG import from Nigeria is another alternative.

In Eastern Europe virtually all imports come from FSU. Several countries have also significant national gas reserves and production. In 1994 domestic production covered 37.7 per cent of consumption in Poland, 69 per cent in Former Yugoslavia, 46 per cent in Hungary and 86 per cent in Romania. The latter controls 50 per cent of total reserves reported for the whole area in the BP gas review for 1995. Poland comes next with 22 per cent. Despite the substantial reserves, Romanian gas production (and consumption) has declined sharply, from a level of 36.4 BCM (38.1 BCM consumption) in 1984 to 16.8 BCM (19.6 BCM) in 1994.

It is likely that FSU will maintain a dominant position in Central and East European markets. Hence some differentiation is likely to take place. In the South, Turkey has already started imports of LNG from Algeria and additional LNG reception terminals are projected in Greece and somewhere at the Croatian coast. Further north the Czech Republic has made an application for purchase of Norwegian gas and has indicated a willingness to pay a premium for such deliveries in order to reduce the current dependence on FSU.

2.2.3 Future supply from the FSU.

Considering the distribution of reserves, FSU - and particularly Russian - supply of natural gas will remain a key factor in European natural gas markets. According to BP, the commercial FSU gas reserves are more than nine times the size of the totals for the rest of Europe. Close to 86 per cent of total FSU reserves are located in Russia and all exports to Europe are currently handled by the Russian Gazprom company.

In 1994 98.7 BCM of natural gas from FSU was distributed among 14 European non-FSU countries. About 65 per cent of the volume was delivered to OECD countries. Germany was the major purchaser with 27.7 BCM. Italy and Former Czechoslovakia came next with 12.9 BCM each, followed by France at 11.3 BCM.

In addition to its exports, FSU is also a gigantic consumer of natural gas. Hence, the future export capacity to Europe will be strongly influenced by the development in 'domestic' consumption. In 1994 close to 82 per cent of total gas production, reported at 671 BCM, was consumed by FSU countries. About 68 per cent of this consumption took place in Russia. Both production and consumption have dropped continuously since the peak in 1990/91. Production has come down around 12 per cent and the decline was particularly large last year with 5.6 per cent. The fall in gas consumption has been even larger, showing a total drop of 17.7 per cent since 1991, and a 7.6 per cent decrease last year. Russian decline in consumption has been somewhat smaller than average for the area, with 13.7% in total and 7% last year.

Despite the sharp and continuous drops in consumption and production, Gazprom is still very optimistic about the future development in Russian gas demand. According to an interview in Euroil (March 1995), the company expects domestic Russian gas demand to surpass the 1993 level with 25-30% by 2010. This view is however strongly contradicted by Stern (1995), who believes that Russian gas consumption will continue the decline and level out at around 300 BCM/year by 2000. If the economy recovers by then, demand can be expected to grow and reach 330 - 375 BCM by 2010. Stern outlines a series of demand side indicators of the current situation as support for his view:

- Macroeconomics decline.
- Enforcement of payment or disconnection of non-paying gas customers. In 1994 officially decreed prices were paid for only 205 of totally 440 BCM of gas delivered to customers in Russia and former Soviet Republics.
- Contraction of energy intensive industry. The former plan economy typically subsidised these industries.
- Conservation and efficiency measures as well as replacement of inefficient plants.
- Moves towards market pricing.

If the 'Stern scenario' comes closest to reality, which is quite likely, Russia will probably postpone the high-cost Yamal development till after 2010, and still have capacity to nearly double deliveries to Europe. According to Stern the Yamal project will only be needed if the joint deliveries to Russia and Europe exceed some 530 BCM by 2010. Any shortfalls may otherwise be covered at a substantially lower unit cost from other sources - e.g. imports from Central Asian FSU countries or by development of the somewhat less costly Shtokmanovskoye field.

2.2.4 African gas and alternative sources of supply.

Algerian gas export to Europe was reported at 28.5 BCM in 1994, and thereby surpassed Norwegian supply by some 2 BCM. Deliveries were split 58/42 between LNG shipments and pipeline transport. In addition to the European exports, Algerian production also serves a growing natural gas market inland and in other North African countries. In a few years, particularly Spain and Portugal on the European side are expected to benefit from a new major pipeline development over Gibraltar, which also is destined to open up the Moroccan market. Commercial Algerian gas reserves are estimated by BP at 3.6 TCM, but may be larger. Total production in 1994 was 50 BCM.

In addition to Algeria also neighbouring Libya has substantial gas reserves, but the development of these resources is so far very modest, the main reason probably beeing the Western political and economic isolation of the country. Libya does not control any pipeline connection to Europe and last year the only significant gas export in this direction was 1.5 BCM of LNG shipments to Spain. In a longer perspective Libyan reserves should still be considered as part of a joint North African supply capacity.

The political instability in this region is a constant worry to European gas importers, particularly to Spain, France and Italy. The civil war situation that has emerged in Algeria has put the importers in a fix. On one hand it would be relaxing to reduce import dependence on the country. On the other hand the current military government is strongly preferred to the alternative, which appears to be a fundamentalist religious regime. The incomes from the gas sales are extremely important for the national economy, and a withdrawal from gas purchases could mean the end of the sitting government. Hence the European trade partners have chosen to continue the imports and hope that the crises will disappear in a few years. Even if the current regime should be overthrown, it is not likely that any new rulers would terminate the lucrative gas deliveries.

Moving further away from Europe, substantial gas reserves exist in Nigeria. Development of LNG export facilities has been planned with a particular view to the markets in North America and Italy. Also the enormous gas reserves in the Middle East may be a future source of supply to Europe. A large scale export pipe line system has been considered. However, unless the development takes a disastrous direction in FSU the realisation of this last alternative still appears to be many years away, and thus certainly does not belong to the scope of this study.

3. KEY FACTORS IN EUROPEAN GAS MARKET DEVELOPMENTS.

Natural gas markets have developed widely differently in various European countries. This applies both to the speed of market growth and to the distribution of end-use applications. The reasons are numerous and complex. Some may be traced back to variations in availability of natural gas, in economic conditions or in unit costs of establishing an adequate infrastructure. Other issues of high importance are national traditions as well as variations in the market structures and tax regimes that are established for the gas as well as for competing energy resources. This section of the study addresses the vital factors for the future development of the European gas market.

3.1 Availability of natural gas.

In the first half of this century most of the densely populated sites in Europe had developed network systems to distribute town gas. This gas, which is a mixture of hydrogen and carbon monoxide, is normally produced from coal. The typical users were private homes and offices, and the gas was mostly applied for cooking and heating. As electricity gained ground, the town gas met increasing competition. In some countries this led to a termination of gas deliveries. In other countries, discoveries of natural gas underground opened a new era for gas distribution. The natural gas could easily substitute town gas in most applications. In many respects the town gas system became a bridgehead for the development of the new resource: Established technology and traditions in use could easily be adopted, and customer groups were taken over.

Compared to oil, the high cost of transport and distribution is an extremely important characteristic with all types of gas. Economy of use is therefore strongly influenced by the distance to extraction point. This was of particular importance at an early stage of development, when no long-distance pipelines existed. In areas close to extraction point the natural gas was made available in greater quantities and at significantly lower prices than city gas. At further distance the establishment of necessary infrastructure depended on extensive and apparently risky investment programs. Investment decisions therefore normally had to include various kinds of risk-share arrangements. In most European countries this meant direct or indirect governmental involvement in the gas sector. As gas grids extended beyond the national borders new developments also came to depend on prearranged sales between producer and distributor.

The first really huge discovery of natural gas in Europe was made in Groeningen in the Netherlands in 1958. Despite the fact that more limited local reserves had already been developed in several European countries, this new discovery significantly altered the whole way of thinking about natural gas in the region. Firstly, the field was so vast that in addition to serving an exploding national gas consumption, large quantities could also be exported to neighbouring countries. Secondly, the discovery initiated the geological interest in the North Sea. The explorations that followed started out by focusing on areas close to the coasts and gave no immediate success. First after years of disappointments, operations were moved into deeper waters, and in 1967 the Ekofisk field was discovered. This gave the starting signal for the enormous explorations and development programmes that took place in this area.

Today the majority of acknowledged petroleum reserves in the North Sea are located on the continental shelves of UK and Norway. Some additional reserves, particularly natural gas, have been found offshore Denmark, Ireland and the Netherlands. On the Norwegian shelf explorations further north have uncovered gas reserves at Haltenbanken and Tromsøflaket. UK has also made discoveries outside the North Sea, particularly in the Irish Sea, where also the Irish Republic has developed several gas fields.

After decades of offshore exploration, the vast bulk of West European natural gas reserves are now concentrated in the North, with the still going strong Groeningen field at the southern rim. Elsewhere, the French production has been in decline for many years and in southern OECD-Europe it is now only Italy that still sustains a substantial natural gas production, that mostly origininates from offshore field developments in the Mediterranean.

In the development of national gas resources, UK and Norway have followed widely different strategies. Due to difficult topography and scarce inland market potential, all Norwegian gas has so far been exported through offshore pipelines to Germany, UK and Belgium.The UK national gas reserves have on the contrary been intensively exploited exclusively for domestic consumption. A flourishing national gas market has in addition been supplied by significant imports from Norway. These imports are now in rapid decline and the British gas market tends to move towards self-containment. In a situation of affluent national gas supply, the UK authorities are reluctant to approve new imports from Norway. Thus, even fully negotiated replacement deals for the field-bound contracts that are running out with depletion of the Frigg-area, have been denied.

At the end of 1995, Norwegian design capacity for annual deliveries of natural gas to the European continent will reach 45.6 BCM. The gas transportation system will then comprise two pipelines to Emden in Germany (Norpipe and the new Europipe) and one to Zeebrügge in Belgium. In addition to this the Norwegian part of the Frigg transport system to UK has now significant spare capacity.

Denmark is feeding a fast growing domestic gas market and also serves some exports to Sweden and Germany from its relatively modest national gas reserves in the North Sea. It is thus likely that the country in a few years will be in need of additional foreign supply. At the moment Norway appears as the most likely candidate to cover the anticipated deficit.

Further developments in the North Sea will include several new pipelines and possible upgrades of existing systems (i.e. installation of compressor stations). On the Norwegian side two new pipelines are planned, one to Germany and one to be landed either in Belgium or France. It is also decided that a pipeline will be installed to connect the natural gas province at Haltenbanken to the infrastructure in the North Sea. Towards Denmark and Sweden, the route and capacity of a possible future connection will strongly depend on the Swedish energy policy, particularly regarding future use of nuclear power. If a rapid wind up of the atomic power stations is decided, which is not very likely, a direct pipeline to Sweden will be actualised. Otherwise a Danish solution seems most likely.

Regarding UK, the installation of the so-called *Interconnector* has attracted much attention. This new pipeline is planned to go from Bacton to Zeebrügge in Belgium and will connect the British gas grid to the continent. Start-up, originally envisaged to be in 1997, will almost certainly be delayed. Considering the current market situation in UK, the British gas industry trusts that the pipeline will take abundant British gas to the continental market, but this assumption is disputed. Several market analysts suggest that the pipeline is likely to run with very low capacity utilisation during its first years of operation, and that the dominant gas flow direction may change much sooner than anticipated by the industry.

In addition to the «internal» production, West and Central Europe are also supplied with natural gas from Algeria and Former Soviet Union (FSU). The Algerian deliveries date longest back in time and were from the start solely based on shipments of LNG. Since 1983 Italy has also imported Algerian gas through an offshore pipeline, but in 1994 LNG still dominated the exports to Europe, totalling 16.3 BCM (BP Energy Review, 1995). Pipeline export to Italy was this year 11.5 BCM. The FSU natural gas supply is based solely on pipeline transport. The 1994 exports to Western Europe were estimated at 64.3 BCM, while Turkey and non-FSU countries in Eastern Europe received 41.6 BCM of natural gas, all according to BP. External gas supply to former East Bloc countries is still 100 per cent controlled by the FSU. Though several of these countries have minor national gas reserves, it is only Romania that has a more substantial national resource base.

On the European continent the infrastructure for natural gas transport is developed to an extensive grid of pipelines that connects most countries together. As an illustration the system was capable of handling FSU transit shipments of 11.5 BCM to France and 13.4 BCM to Italy in 1994. However, in spite of the numerous interconnections, the national markets have so far mostly maintained their isolated positions and a common European gas market still appears to be some years away.

3.2 National energy policies.

Energy policies in Europe were strongly influenced by the two heavy price shocks on oil, the first one invoked by OPEC after the blocking of the Suez Canal in 1973, and the second one resulting from the Iraq-Iranian war, that broke out in 1979. Responding to the shocks, most West European countries implemented strategies to reduce dependence on oil imports from the Middle East. The base element in these strategies was an endeavour to secure national control and diversification in energy consumption. It is important to remember though, that particularly in the seventies, it was widely believed that the oil price would continue its escalation. Market mechanisms therefore reinforced the policy efforts to stimulate investments in increased energy efficiency and in the development of European based energy sources. Petroleum activities in the North Sea got a strong push forward in this period.

As most European countries only controlled small amounts of petroleum, focus was directed at other sources of energy. On one hand this created a renewed interest in the old energy major - coal. On the other hand many countries embraced the new nuclear technology and initiated huge investment programmes for the construction of atomic power schemes. Thus, the consumption of nuclear energy in 1994 surpassed the 1978 level by more than four times. In this period nuclear energy increased its share in total primary energy from 3.3 to 14.6 percent (BP Energy Review).

In the eighties both coal and nuclear energy became increasingly influenced by environmental concerns. New and stricter regulations on security, waste handling and emissions, contributed to substantial increases in unit costs of production. At the same time prices of oil in particular, but also of natural gas, returned to a lower level, and thereby further weakened the competitive position of coal and atomic energy. Severe accidents, like the one at Chernobyl[7], have nurtured a growing distrust in nuclear energy. Throughout most of western Europe popular resistance is now so strong that any significant further expansion of this sector seems unlikely. Indeed, some countries are even considering a stepwise closure of own production[8]. The future of coal usage is also darkened by its environmental repercussions, in particular by the high emissions of greenhouse gases[9] compared to other fuels. Several countries have already declared targets for reductions in own emissions. These will be hard to fulfil without a substantial decrease in the consumption of coal.

Even though the actual settings for the energy sector are substantially changed, elements of the politics initiated in the seventies still remain. Two important examples are the German protection of the national coal industry and the special French devotion to nuclear energy[10]. In Germany today, regional politics and employment considerations have replaced security of supply as leading motives to maintain coal subsidies. In France, the nuclear support obviously must be understood in the wider perspective of industrial and political ambitions, including the military connection. It is also worth noting, that the reluctance to use imported petroleum in electricity generation is not specific to France and Germany, but is shared by politicians and national industries in many European countries. This is for one thing illustrated by the distribution of governmental economic support to energy research in IEA countries, shown in figure 3.1.

Both the German and French policies substantially constrain the market potential for natural gas in the electricity sector. Similar effects are also observed in other European countries, though often enforced by other and less visible mechanisms. A striking illustration of this point, has been the liberalisation of the gas market in UK. When British Gas a few years ago was deprived of its monopoly in gas distribution, the resulting competition initiated a boom in the use of gas in electricity generation. This clearly demonstrated that British Gas, probably in some kind of understanding with the coal and oil industry, for many years had conducted a price regime that almost excluded power stations as customers. As all other European gas markets still are subject to monopolistic regulation, the UK example is an indication of what may happen if the markets are deregulated. It is obvious that power generation will be strongly affected by a radical market reform in gas distribution. The other way around, the selection of fuels for power generation may very likely become the single most important factor for the development of natural gas consumption in the next decade. According to IEA,

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7 Chernobyl (FSU), Sellafield (UK), Three Miles Island (USA)

8 i.e. Germany and Sweden. (In the latter a referendum held in 1980 gave majority for closure)

9 Particularly carbon dioxide.

10 In Germany subsidies to the national coal industry for the period 1996 to 2005 are financed by a levy on electricity consumption (Ausgleichsabgabe - regulated by the Energy Policy Act of April 1994). Current tax level is 8.5% in West Germany and 4.25% in East Germany, the latter gradually increasing to West German level. Coal based power stations are bound by long term contracts to buy domestic coal to meet a certain percentage of their needs, currently around 87%. In addition to this, Germany has a special tax on natural gas, currently at around 0.036 DM/CM

In France a special tax applies to all purchases of more than around 1190 cubic meters (CM) of natural gas annually. The current tax level is around FF 0.07 per CM.

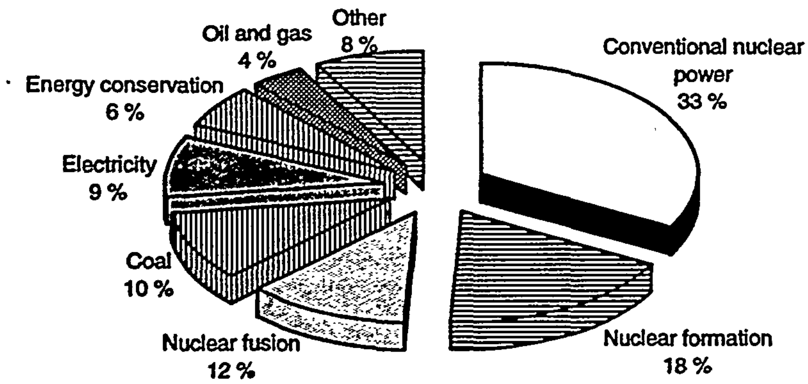

Figure 3.1 Distribution of public funding for energy research in IEA-countries, 1988-90.

Source: Energy Policies of IEA Countries, 1990 Review, OECD, Paris 1991.

the share of gas in electricity production in OECD-Europe was only 6.5 percent in 1992. Should the share be raised for instance to the Japanese level - at 19,5 percent - it would require an additional 60 to 70 BCM of gas, based on this year's figures.

In Central and Eastern Europe (CEE) the energy policies are in rapid transformation following the breakdown of the former East-bloc trade system. Since the beginning of 1990 an intensive energy pricing reform has been introduced (Energy Policy 1994, vol. 22.6). The former system of centrally allocated energy did not reflect economic costs through prices, and most fuels were significantly under-priced (Cofala, 1994). The relative price of coal remained below 50 percent of Western European levels for most of the 1980s. For gas and oil the differences were significantly smaller, with relative prices swinging around 80 percent of Western European levels. The price reform and phasing out of the central allocation system has been followed by a sharp increase in energy prices and a large drop in energy consumption. From 1989 to 1992 gross energy consumption in the CEE area decreased by 25 percent. Consumption of natural gas dropped 26 percent. However, it should not be forgotten, that these changes are not primarily results of the energy reforms. They must be seen in light of the whole complex of problems connected to the transition from plan to market economy and the collapse of the East-bloc trade systems.

As a follow up of the price reform, the organisational structure of the energy sector in CEE has been reconsidered. Restructuring processes are so far most advanced in the Czech Republic, Hungary and Poland, but also Bulgaria and Romania are discussing the issues. Common elements in the restructuring programs are:

- *liquidation of monopolies*
- *commercialisation and privatisation*
- *splitting of fuel network systems according to functional roles (i.e. generation, transmission and distribution)*
- *creation of new laws and regulatory bodies*

Opinions differ widely on the influence of the reforms on future energy usage in the area. Official CEE-projections are rather conservative in anticipating relatively modest shifts in the composition of energy consumption. They also suggest that the energy consumption soon will return to a rapid growth path as the economies recover after the implementation of market reforms. Optimism is particularly outspoken in Poland, Hungary and the Czech Republic, where economies tend to be improving from the heaviest recession. According to official estimates, total CEE energy consumption will be back at 1989-level in 2000, and then continue to grow at an annual rate of about 1 percent until 2010. It is suggested that nuclear power will grow fastest and that it will have doubled its share in total energy to about 14 percent in 2010. Coal is expected to stagnate and will not regain the 1989-level. Its share in total energy will drop from 54 to slightly above 42 percent during the period. Natural gas consumption is expected to grow slightly faster than the total, and will reach a share of 20.5 percent in total energy in 2010, compared to 19,7 percent at present.

Projections based on model calculations at the International Institute for Applied Systems Analysis in Austria predicts far more radical changes (Cofala, 1994). These estimates are substantially more pessimistic about the future of nuclear energy and coal. They anticipate that restructuring of industry and improved energy efficiency will result in large energy savings. Though total energy consumption is predicted to increase from the 1992-level, it is not expected to return to the 1989-level until 2010. Shifts in relative prices are also envisaged to cause dramatic changes in the composition of energy. Consumption of coal will decrease by 30 percent till the turn of century and a further 24 percent in the next decade. Its share in total energy will be more than halved, to about 24 percent. Natural gas is assumed to have the most prosperous future. The consumption in 2000 is expected to reach 122 million tons of oil equivalent (Mtoe) as compared to 97 Mtoe in 1989 and 71 Mtoe in 1992. By then natural gas will have reached a share of 30 percent in total energy and the share is expected to increase further, to about 37.5 percent in 2010.

3.3 Market organisation and legal framework.

The European Union is working on a proposal[11] on petroleum, natural gas and electricity. According to an optimistic Mr. Santer[12] the proposal may be completed this year. On a general level the work aims at securing that the European Commission receives detailed information on planned energy investment projects of interest to the Union so it can keep an overall picture of the capacity and equipment plans in the energy sector. The highest ambitions are set for a liberalisation of the internal market for electricity which today is featured with one of the highest degrees of monopolistic structure in the EU. Enhanced competition in this area has a high priority for the Commission, but the member states have so far not succeeded in agreeing on effective measures. Negotiations on the issue have been in political deadlock for three years. The principal contention applies to the choice between a so-called *Single buyer model (SBM)*, proposed by France, and the concept of *third part access (TPA)*[13]. A possible compromise may be some sort of parallel establishment of the two systems.

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[11] EU: COM(95) 118

[12] Leader of EU Commission in a speech to the European Parliament, 15 February 1995.

[13] **TPA** (third part access) allows direct contracts between producers and consumers while an independent third part is responsible for running and maintaining the means for transport and charges a tariff for use of capacity. **SBM** (single buyer model) allows only one company/organisation to be seller of the commodity and owner of the transport facilities. Producers are enforced to sell to the SBM or the SBM may even itself be a producer.

At the moment natural gas markets in Europe do not seem prepared for a rapid liberalisation and integration. What happens in the electricity sector will nevertheless be of great importance. A liberalisation here will directly affect natural gas consumption in several ways. Firstly, it may alter the competitive position of electricity versus gas and other kinds of energy. Secondly, a reform may also contribute to substantial changes in the pattern of fuel selection for power generation. Indirectly, the success or failure of the electricity reform will certainly also influence both the timing and the configuration of a subsequent market reform in natural gas. However, in lights of the profound disagreements on the current proposal, the Commission will probably hesitate to invoke a similar dispute on natural gas right away. A full liberalisation is therefore unlikely to take place before the turn of the century. Still, it is important to note that most analysts and sector companies expect the reform to come and they discount it in their current attempts to position for the 21st century.

With regard to transmissions of gas between countries, two important agreements are established. One is the EU Transit Directive that requires member states 'to facilitate the transit of natural gas between high pressure transmission grids'. The other is The Energy Charter Treaty, signed in Lisbon in December 1994. This last treaty includes most OECD member states (including EU), Central and Eastern Europe and FSU. It aims at improving conditions for energy co-operation and trade between the contracting parties. The principal message is: «Allow freedom of energy transit on just and non-obstructive conditions - including establishment of capacity - unless transport can be demonstrated to damage transit country's own energy system.» Both agreements include provisions for how to handle disputes, but as yet no precedence is set for either of the two.

3.3.1 Gas imports and transmission: concessionaires and national monopolies.

On national levels natural gas markets in Europe are still relatively closed and most often dominated by one single or a few major companies. With a few exceptions, imports and transmission of gas is strongly regulated by the governments. The control is either exercised directly through publicly owned monopolies, or by some kind of concessionaire system. Privileged companies will typically own at least the high pressure parts of the networks and also control the whole chain of trade from purchases and as far as the 'city gate'. At this point the gas is often taken over by local distribution companies, but some transmission companies also carry out the distribution.

Even where transmission and distribution is commercially separated, transmission companies may be substantial shareholders in distribution. In Germany for instance, Ruhrgas is one of the most influential owners in Verbundnetz Gas (VNG) - the major distribution company in former DDR areas. In countries with domestic production, national transmission companies may also take part in exploration. This is the case with British Gas which is one of the major UK gas producers. It also happens in Germany where companies like BEB[14] and MEEG[15] are at the same time transmitting and distributing gas and exploring domestic gas fields. The two latter are also an illustration of the fact that several of the major petroleum companies regard downstream gas activities to be an attractive business. Responding to the new trends in the direction of a more open and integrated European gas market, we see that also the Norwegian

[14] BEB Erdgas and Erdol GmbH is a 50:50 joint venture between Esso AG and Deutsche Shell AG.
[15] MEEG - Mobil Erdgas-Erdol is a wholly Mobil owned company.

petroleum companies are actively pursuing a foothold downstream. Saga Petroleum tried, but failed to develop a co-operation with German Wintershall. Statoil and Norsk Hydro have succeeded to get 'inside' through Alliance Gas in UK, and in the Netra network joint venture in Germany.

In Italy the ENI daughter SNAM holds de facto monopoly in gas imports and transmission despite the introduction of a common carrier principle in legal terms. SNAM is also a major shareholder in the transmission pipelines that carry gas from Holland (TENP in Germany and Transitgas in Switzerland) and FSU (TAG, starting at the Czech/ Austrian border). ENI, the formerly state-owned energy giant, was privatised late 1995.

The French market is fully controlled by the state owned Gas de France. This vast company, with more than 27 000 employees, covers the whole chain from gas purchases via transmission to distribution and associated services. Possible privatisation of the company has been discussed, but is not likely to take place in the near future.

3.3.2 Germany.

Unlike most other European countries, Germany has no formally defined monopolies in imports and transmission of natural gas. Still the market has not until recently faced any real competition. The market has long been and still is strongly dominated by Ruhrgas, which owns most of the networks in Former West Germany. In 1994 the company controlled around 70 percent of German gas transmissions. It handles almost all imports from Norway and also most of the imports from Russia. In Former East Germany, Ruhrgas has secured its position through heavy investments in the former DDR distribution company Verbundnetz Gas (VNG).

In lack of public regulations, the gas industry has itself organised a system of demarcation agreements which divide the country among distribution companies according to geographically defined areas of interest, though, after reunion, the harmony has been broken by the BASF subsidiary Wintershall, which is aggressively seeking to increase its market share in supply and transmission. In 1994 the company reached a 10 percent share in the domestic market, but targets at a 15 percent in the near future (DN, 8.5 1995). To meet this goal Wintershall has initiated a vast pipeline construction program. Wintershall has also made several applications for purchase of Norwegian gas, but these have all been turned down by the Gas Negotiation Committee (GNC). The official motive for Norwegian denials has been the fear of gas-to-gas competition in the German market. Suspicions have been voiced though, that the decisions are at least as much resulting from Ruhrgas pressure. Anyway, Wintershall now seems to have secured gas supplies through a formalised co-operation with Gazprom. It has materialised in WINGAS - a joint venture between the two - which is set up to handle the German gas market. The arrangement will probably guarantee sufficient Russian gas supply to the company, but still WINGAS gives high priority to solutions that may broaden the supply basis. A differentiated supply is expected to be of strategic importance in the future German market. New requests to Norway is therefore one alternative and WINGAS will certainly also look for other sources; in UK, Algeria or elsewhere.

Market reforms have been seriously considered in Germany. A legal proposal on TPA was actually raised in the Bundestag some time ago, but was later withdrawn for further deliberation[16]. Influential spokesmen for the gas transmission companies are now counteracting a renewed proposal and are eager to maintain that competition and third party access can be attained without interference from the authorities. Several analysts interpret the Netra joint venture - between Ruhrgas / BEB and the Norwegian gas producers Statoil and Norsk Hydro - to be an important industry contribution to this debate (NOR, 10/1994, pp. 12-21).

3.3.3 UK.

During first part of the eighties the British gas market was still completely dominated by British Gas (BG), which held a monopoly of transmission, distribution and retailing. The Oil and Gas Enterprise Act 1982 allowed for supply of gas to end-users by other parties. But the act did not initiate any real changes, as no one applied for access to the grids. Only in 1986 did things start to change. That year British Gas was privatised and the Gas Act 1986 created the Office of Gas Supply (Ofgas) and appointed a director-general with a duty to «enable» competition in the contract market. As competition still emerged very slowly, the Monopolies and Mergers Commission (MMC) in its 1988 report expressed concern that British Gas by virtue of its market dominance *«may be expected to operate against the public interest by deterring new entry to the market»*. MMC required British Gas to issue more information about carriage charges and to keep its transportation and purchasing/marketing operations strictly separated. In 1990 Ofgas initiated a revision of the company's transport charges, resulting in tariff reductions ranging from 20% to 40%.

As British Gas still owns most of the transport and distribution networks in UK, the dispute on terms of competition has continued. Continued disagreements between British Gas and Ofgas initiated a new MMC review and this time the whole gas industry was covered, including transportation and storage. The Commission's report was published in August 1993 and recommended that:

- BG trading activities should be divested, implying separation of transportation and trading, by 1997
- threshold for monopoly supply to tariff customers should be reduced from 2500 to 1500 therms.
- transportation charges should be based on a 6.5-7.5 rate of return on new investments under current conditions.

Late 1993 it became clear that the British government would not require a break-up of BG. Instead the Department of Industry proposed to internally separate the company's transport and trading divisions and also decided to carry out a phased opening up of the domestic market, leading to full competition by 1998. According to the plan, BG's tariff monopoly will be ended in April 1996 and the competition for the household market will be opened up gradually to April 1998.

Following the market reforms a series of new companies have entered into domestic gas marketing in UK. Despite a rapid growth in gas consumption, particularly due to fuel substitution in power generation, gas-to-gas competition has increased substantially, leading to a

[16] A conflict on TPA has also been handled by a German court. - ref. Financial Times, EC Energy Monthly: *Selfant questions gas demarcation, Wieh loses TPA battle*, July 1993, ECE 55/18.

sharp fall in spot market gas prices. In spring 1995 the price for short term gas deliveries was reported at $62 per 1000 cubic meters[17], which is down around 60 percent compared to the preceding year (DN, 5 May 1995). Many of the newcomers in the market are rather small companies with a fairly modest financial basis. It is thus expected that the current surplus of supply and the fierce competition will lead to a substantial reduction in the number of gas marketing companies. But also BG is facing severe problems in its adaption to the new environment. The company appears to have come in a squeeze between enduring "take or pay" liabilities in its gas purchases, and rapidly falling market shares in the liberalised market segments.

3.3.4 Norway.

All sale of Norwegian gas is organised through the Gas Negotiation Committee (GFU). The committee is headed by Statoil - the fully state owned national petroleum company - which is supplied by the two other Norwegian oil companies, Saga and Norsk Hydro. GFU prepares and carries out negotiations with interested buyers of gas as far as to agreement of a contract. The contracts must then be approved by the authorities, represented by the Industry and Energy Ministry, which also decides to which fields the contract shall be connected. Since 1993 the ministry has been assisted by a Gas Supply Committee (FU), which now includes twelve of the major licence owners on the Norwegian shelf.

The establishment of the GFU in 1986 was intended to serve several purposes. Upstream the committee should contribute to a more co-ordinated usage of the total gas resources. Before that date, Norwegian gas was sold on depletion contracts directly connected to the physical field developments. By the introduction of GFU the link between gas sales contract and delivery source was broken or at least significantly relaxed. Starting with the Troll contracts it is now the government that formally decides from which fields agreed gas deliveries will flow. This arrangement has attached more of the supply responsibility to Norwegian authorities. On the other hand the flexibility in resource usage is substantially increased, a property which is extremely valuable in an area where knowledge on the commercial resource base is continuously altered through new information from production, appraisal drillings and the development in the natural gas markets.

Downstream the reorganisation aimed at strengthening the national trading position towards the purchasers which typically are big companies with total or at least considerable monopolistic power in domestic gas markets. It is also worth noting that several of the major foreign licence holders on the Norwegian shelf are involved in transmission and distribution of gas in continental Europe. This is particularly the case in Germany, which is by far the most important market. The GFU system has thus been intended as an instrument to maximise the national value of Norwegian gas resources and has particularly aimed at avoiding potential gas-to-gas competition.

The GFU arrangement is controversial. The institution has never been popular among the foreign licence owners in Norway, who have been particularly dissatisfied with their own influence through the system. The establishment of FU in 1993 may partly have offset this problem. Another and probably more severe problem is the growing distrust of GFU by

[17] Equals $1.72 per MMBtu.

foreign authorities. Still, the system was accepted by the European Commission - though not without hesitancy - when the Norwegian application for membership in the European Union was approved in 1994. But already during spring 1995 the GFU again hit the headlines when it turned down an application for purchase of gas from German Wintershall that was supported by Norwegian Saga. Here the interests of Saga, which itself is a GFU member, were completely overrun by the two other members. The denial was made on the basis of principle without any further negotiations on price or other contract conditions. This gave rise to speculations and media allegations that the decision was influenced by Ruhrgas. As a consequence, German competition authorities decided to investigate the case. On request from the «Budeskartellamt» Ruhrgas strongly denied that the company had participated in any activity destined to reduce competition. The German authority accepted this answer but decided to direct a further request to the European Commission to have the GFU considered in relation to the antitrust provisions in the Treaty of Rome (DN, 28 April 1995).

The future of the GFU is unsure. Norwegian authorities will probably be pragmatic to changes in the practical arrangements. On the other hand, they will not easily accept any conditions that remove or strongly weaken the authorities' ability to co-ordinate production and sales of Norwegian gas.

3.3.5 Former Soviet Union (FSU).

In FSU Gazprom has largely taken over the roles and possessions of the former Soviet Ministry of the Gas Industry[18]. It owns all the high pressure transmission lines in Russia and in 1993 also produced 93.4% of all Russian gas[19]. Gazprom carries the domestic gas as far as the 'city gate' where it is passed over to local distribution companies under the umbrella of Rosgasifikatsiya. With many of the people from the Soviet era retained in senior positions, Gazprom has also preserved much of the structure and ways of thinking from the central plan economy and still very much tends to fancy upstream 'mega-projects'. Though it has undergone (Russian style) privatisation[20], the company has resisted all attempts to have it broken up according to functional roles. Bearing in mind the extreme importance of gas both in the Russian energy balance and as a collector of foreign currency, it is quite understandable that politicians have been cautious to change the rules of the game in this area. Particularly since the gas industry has remained by far the most successful industrial sector of the new Russian economy, as indeed it also was during the last decades of the Soviet era.

All exports of gas from the Commonwealth of Independent States (CIS) to Europe is handled by Gazprom through its export division Exportgaz. Since 1990 the company has been reforming the traditional sales strategy of the former Soviet system, which was to deliver at the border of the importing country with no Gazprom involvement in the further transportation and marketing of the gas. The new policy is to take active part in downstream activities and to

[18] Described in J.P. Stern (1995) who also refers to Arild Moe (1994) for further background information.

[19] The remaining 6.6% of gas was produced by oil production companies, mainly as associated gas from West Siberian oil fields controlled by Rosneft Association. An interesting point is that despite its control of current production, Gazprom owns only 50% of the 49 TCM of proven reserves. (*Gazprom Study Cracks open Secrets of the Gas Giants'*, World Gas Intelligence, 27 January, 1995, p. 5)

[20] Gazprom is now organised as a 'Joint Stock Company' and 51% of its shares have been sold to employees and the Russian public. A planned sale of further 9% to foreign investor was postponed in March 1995. This sale has earlier been coupled with the financing of the Yamal development.

achieve this goal Gazprom has entered into a series of joint ventures with established transmission and marketing companies in the importing countries. Examples are:

- WINGAS with Wintershall in Germany (Wintershall is a subsidiary of BASF)
- Gaz und Varenhandelshaus (GVH) with OMV in Austria
- Gasum with Neste in Finland
- Fragaz in France
- Panrusgas with DKG in Hungary
- Promgaz with SNAM in Italy
- Gaztrading and Europol Gaz (for construction of pipeline) with POGC in Poland
- Wirom with Romgaz and WIEH (another German Gazprom jv) in Romania
- Tagdem with Petrol in Slovenia

The purpose of the joint venture strategy is partly to capture some of the extra profits believed to be earned in the downstream markets. Furthermore, Gazprom hopes to promote future Russian gas sales by extending and deepening its contacts with influential players in the national markets. In Germany the joint venture with Wintershall has already built several major pipelines (MIDAL and STEGAL) and has - as the only company - started to aggressively challenge the interests of Ruhrgaz. It is a paradox though, that Ruhrgas continues to be the major customer of Gazprom outside the FSU.

In Eastern Europe, the dominance of FSU gas in imports is nearly total and Gazprom has occasionally attempted to make use of this position to enforce joint ventures with national transmission companies. This is the case in the Czech Republic and Slovakia. A renewal of long term gas sales contracts after 1998 has here been made conditional upon the settlement of a joint venture between Gazprom and the national transmitter, Transgas (DN, 20 July 1995). So far the Czech and Slovak authorities have resisted the pressure and have also further annoyed the Russians by making an application for Norwegian gas supplies. Also other former East-bloc countries may in future wish to diversify the gas supply and hence be willing to pay a premium for alternate imports. On the other hand, for countries lsuch as the Czech Republic and Slovakia and Poland it must be quite reassuring to know that the bulk of FSU exports to Western Europe flow or will flow through their countries. A too rigid Gazprom policy may thus be met by higher transit tariffs on FSU exports to other European countries.

3.4 New infrastructure for natural gas.

In its 1993 white paper on growth, competitiveness and employment, the Commission of the European Communities strongly emphasised the importance of well-functioning networks[21]. According to the paper any shortcomings in the development of proper energy transport networks will in general not be attributable to financial problems. Except for some projects in peripheral regions of the Community, investments in this sector are generally lucrative and should not require financial support from the public sector. The Commission maintains that imperfections most often result from administrative constraints that hamper private sector investments.

On the basis of decided and planned investments in trans-European electricity and natural gas networks, the Commission has estimated that total investments in this area may possibly reach ECU 13 billion by the end of the decade. With regard to natural gas a wide spectrum of projects are anticipated, both to improve the internal EU distribution and to increase supply capacities from external sources. Internal plans cover the setting up of infrastructure to develop new markets, in particular in Northern Ireland, in Portugal and on the Mediterranean islands Corsica, Sardinia and Crete. Major extensions of existing grids are also scheduled in Spain, in Germany's New Länder and in mainland Greece.

A further growth in gas consumption in the Community will inevitably require the establishment of additional capacity in transit pipelines. In the north, the plan is to supply the new market in Northern Ireland by a pipe connection to the Irish grid, which has already been linked to the main UK network. In the south, the development of a Portuguese market is likely to be based on pipeline supply from Spain, perhaps in combination with some LNG. Combined with expanding gas usage in Spain, the new market requires a significant increase in the supply capacity to the whole Iberian peninsula. A first stage in satisfying this demand has been the installation of a pipeline link from Spain to the French gas network. A possible second stage will imply the construction of a trunk line from Algeria to Spain.

Existing gas grids in Europe have typically expanded as separate trees rooted at supply hubs, like Zeebrügge in Belgium and Emden in Germany. Combined with conflicting interests of ownership, this has contributed to the development of a set of relatively segregated systems. Construction of new interconnections is therefore a natural part of a program to strengthen the European gas networks. In the short term such measures will improve the security of supply. In a longer perspective they may form the first steps in the development of an integrated common market for natural gas in Europe. The white paper list of scheduled and planned interconnections includes two pipelines from Germany - one as a link to the pipelines from Zeebrügge and one to connect to the network of former East Germany. Another important interconnection is the long-expected link between the Continent and the UK gas market.

[21] COM(93) 700 final, Brussels, 5 December 1993.

3.4.1 Major infrastructure developments in Germany.

Germany is of particular importance for the development of natural gas markets in Europe. Not only is it the major gas-consuming country, it also has a geographical location that makes it a natural hub for further distribution of gas to other European countries. The ongoing programs for construction of new infrastructure for gas in Germany, should therefore be given special attention. German plans for the next years are ambitious and physical developments foreseen will significantly alter the supply situation in Central and Western Europe. Indirectly the construction programs may also influence the ongoing debate on market reforms. As the two major antagonist companies - Ruhrgas and WINGAS/Wintershall - are now building pipelines into mutual core areas, competition is presumed to intensify strongly, at least in the German market..

With regard to pipelines, several new projects are coming up. WINGAS/Wintershall has for several years been developing a transmission line (MIDAL), which stretches from the eastern German border to the North Sea, close to Emden. Next year the company will also start construction of a pipeline (WEDAL) that by 1998 will give access to the industrial core areas at Ruhr in the Rhine valley. The pipeline may later be extended and connected to the Belgian market. Further south in Germany, WINGAS has planned yet another pipeline that will start at the Polish border and pass through Munich to Basel in Switzerland. In addition to opening up new German areas for WINGAS marketing of gas, the project will create a new channel for Russian gas exports to Switzerland, France and Italy. It will be an important element in the Russian effort to create an alternative gas corridor through Belarus and Poland and thus reduce the extreme dependence on Ukraine for gas transits to Europe.

Ruhrgas on the other hand is also involved in major pipeline developments. Together with the Shell/Esso owned BEB, the company has formed an alliance with Statoil and Norsk Hydro to complete the NETRA trunk line system. The pipeline will pass from Etzel via Wardenburg and Achim to Salzwedel, which is an important bridgehead to gas distribution in East Germany. At the North Sea, Etzel is already connected to the terminal at Emden. Also the last part of the transport system from Achim to Salzweldel, does exist. The pipeline from Wardenburg to Achim is under construction by Ruhrgas and BEB, while the part from Etzel to Wardenburg still remains to be built by the new consortium. The project is designed for an initial capacity of 16 BCM annually, that may be increased to 18 BCM. Total price is calculated to about 1 billion D-mark. The Norwegian companies are offered a 25% share in the project and related capacity will be used to carry already agreed annual deliveries of 4 BCM of gas to VNG. The remaining capacity shall be disposed by the German companies. However, the Norwegian partners are given an option to further increase their common share to 33%, provided that it is done to cover increased deliveries of GFU-gas (NOR, 10/1994).

3.4.2 UK and the Interconnector.

In December 1994, it was finally decided to build a pipeline link from the UK terminal of Bacton to the Belgian hub at Zeebrügge. Start up was envisaged for 1998, but will almost certainly be delayed. The pipeline is primarily intended for exports of gas from UK, and the design capacity in this direction is set to 20 BCM annually. Technically the flow may easily be reversed to take a maximum of 10 BCM in the opposite direction, but this option still awaits governmental approval in UK. Total cost of the project has been estimated at £390-400 million (Wood Mackenzie, April 1995).

The Interconnector group has 9 participants: 4 oil companies, 4 transmission companies and one power company. British Gas is the major owner with a 40 percent share. British Petroleum, Conoco, Elf and Gazprom have taken a 10 percent share, while Amerada Hess, Distrigaz, National Power and Ruhrgas each hold a 5 percent share. Gas de France and the two Norwegian companies, Statoil and Norsk Hydro, applied for partnership but were denied by British authorities[22]. Transmission rights in the Interconnector will be distributed according to the companies' shares.

The British gas market is at the moment in a position of surplus inland supply. On this background the Interconnector is intended as a measure to improve the profits of the UK gas industry. The effects are expected to accrue partly through new incomes from gas exports abroad and partly as a consequence of domestic price increases as part of the gas supply is removed from the national market. Several partners in the consortium have pronounced an optimistic view on possible future gas exports from UK to the continent. However, the concept is strongly questioned in a recent report from Wood Mackenzie (April, 1995). The report emphasises that UK proven and likely reserves theoretically are sufficient to preserve a surplus production capacity well into the next century, even if domestic consumption continues its rapid expansion (up to above 100 BCM annually in 2000). Despite that, the analysts see several severe obstacles to an export scenario. One is that UK gas at Zeebrügge will meet hard competition from less costly Norwegian gas. It can therefore be difficult to obtain gas prices that are high enough to carry the needed field investments to maintain a sufficient production level. Furthermore, the currently acknowledged British resource base is not sufficiently large to have continental buyers stop questioning the credibility of UK as a long term gas supplier. In the strongly regulated continental natural gas markets, this element is considered to remain a major drawback for UK exporters. In these markets natural gas contracts are normally agreed on long term 'take or pay' conditions and the major players in the nearest and most interesting markets have already contracted deliveries to cover as good as all expected demand till after 2000.

Wood Mackenzie concludes that the realistic market potential for the Interconnector during its 'export window' is rather weak if the current continental market structure is maintained. The situation could however change substantially if a radical market reform with TPA should be introduced. But even then the liabilities in existing contracts would probably prevent a momentary transformation of the market system. According to Wood Mackenzie a likely scenario for the Interconnector is that it will transmit only small quantities of gas during its first years, and primarily serve as an instrument to balance prices between national spot markets on both sides of the Channel. Furthermore the basic flow direction is likely to change sooner than anticipated by UK authorities.

[22] The refusal of the two latter was due to the continuing dispute on the Frigg pipeline. This transport system was built in the mid-seventies to export Norwegian gas from the Frigg field to Scotland. Production under the original contracts is now in rapid decline, leaving the pipeline with an increasing free capacity. British authorities do not however accept this capacity to be filled with gas from other sources without a thorough revision of transport conditions. The dispute appears to be at a deadlock and no solution is expected before the Interconnector is completed.

Some analysts have suggested that the capacity utilisation of the Interconnector may be improved if UK could co-operate with Norway. If a solution is found to the deadlocked Frigg dispute, there is a chance that the Bacton line may continue exports as swaps for Norwegian gas landed in Scotland.

3.4.3 Norwegian export capacities and planned increases.

After Europipe I came on-line during 1995, Norwegian pipelines to the continent have reached a total design transport capacity of around 45 BCM. This is divided between the 12 BCM Zeepipe line to Zeebrügge in Belgium and two pipelines to Emden in Germany, of which Europipe I also has a 12 BCM capacity, while the older Statpipe/Norpipe system has a name plate maximum capacity of 21.6 BCM at the Emden terminal. Both Zeepipe and Europipe I are comprised in the Troll/Sleipner project that is still not fully developed. After the participants in the Troll contract exercised to the full extent their final volume options, it is now clear that the plateau level of Troll sales will reach 45 BCM by 2005. At least two additional pipelines are needed to handled total Norwegian gas sales by then. It is already decided that one line of 12 BCM capacity, called Europipe II, will be landed at Emden. France was recently chosen as landing point for a second line with a 14 BCM design capacity. The French alternative has long been evaluated agianst a second pipeline to Zeebrügge. Important for the decision was that contracted gas sales to France and Spain have now reached a sufficient level to fill the capacity of a new pipeline. The UK decision on landing the Interconnector at Zeebrügge is a further argument in the same direction.

From production start at the Frigg field in 1978 Norway has also exported gas to UK. This gas is transmitted through the Frigg pipeline system of which the British part has a capacity to carry 11 - 12 BCM annually. However, the utilisation of the system is already at a very low level and is further decreasing. The reason is that production under the original Frigg concession is in sharp decline and the UK government denies any replacement with gas from other fields to be shipped to UK at the terms agreed in the concession. The dispute on the use of the pipeline has been at a deadlock for several years and is at the moment blocking further Norwegian gas sales to the UK. For the time being British authorities appear to be well suited with the situation and it is widely believed that no solution will be found until the Interconnector is on-line in 1997. In the scenario analysis we anticipate that normal gas trade conditions between Norway and UK will be re-established by the end of the century.

By 2000 it is also likely that a connection will be created from the Norwegian sector in the southern North Sea to the Danish natural gas network. Danish gas production is currently sufficient to cover the national demand which in 1994 reached 2.75 BCM (BP Gas Review, 1995) and an export of around 1.7 BCM to Sweden and Germany. However, the acknowledged Danish gas resources are fairly limited and the consumption is expected to increase substantially both in Denmark and in the export markets, particularly in Sweden. Additional supply may thus be needed and Norwegian gas appears to be the most likely candidate to meet the new demand. The design capacity for a possible new pipeline to the Scandinavian market will be strongly influenced by any changes in the Swedish nuclear energy policy.

3.4.4 The Maghreb-Europe trunk line.

Plans for the construction of a pipeline system for natural gas exports from Algeria to Morocco and Spain have already been developed. The Spanish link will cross the Strait of Gibraltar and be connected to the existing network at Cordoba. The Europe-Maghreb pipeline Ltd., a subsidiary of Spanish Enagas, will be responsible for the financing of the estimated $2 Bn project. Of total costs, $700Mill. is required in Algeria, $1Bn. for the Moroccan part and $300Mill. for the Spanish link. Completion, originally envisaged for 1996/97 (Euroil, June 1994) is likely to be delayed due to the violent conflict that is going on between Islamic fundamentalists and the government in Algeria.

The primary intention with the pipeline is to supply the gas markets in Morocco and on the Iberian peninsula. But the project has already from the start been evaluated in a wider European perspective. The possibility of future supply through this line to France and other European countries has attracted the interest of Gaz de France and Ruhrgas, which are now involved in the project together with Enagas, Gas de Portugal, Sonatrach and Moroccan SNPP. The European Union has also expressed strong interest in the construction of the pipeline, and as much as 40% of total investments may be financed through the European Bank of Investments.

3.4.5 New pipelines to increase and secure FSU exports[23].

The major part of natural gas exports from the Commonwealth of Independent States (CIS) to non FSU countries are channelled through Uzhgorod at the western Ukrainian border. The total export capacity at this node amounts to 78.8 BCM annually, split with 75 BCM on the major four pipelines complex which enters the Czech and Slovak republics, and a smaller line, with a capacity of 3.8 BCM (Stern, 1995 - p. 71), passing into Poland at Brest. Poland is also supplied by another pipeline from Kobrin with a capacity of 7 BCM. In the north a 4 BCM line carries gas from St. Petersburg to Finland. In the south at Ismail an export line with a capacity of 20 BCM serves the markets in Romania, Bulgaria and Turkey, while another line may carry up to 4 BCM annually to Hungary and Serbia.

Gazprom, the monopoly Russian transmission and export company, intends to expand export capacity to European countries from actual level at 115 BCM to 140 BCM in 2000 and further to 200 BCM in 2010 (Stern, 1995 - p. xvi). In 1994 Russia signed an agreement with Poland on the construction of a new trunk line for natural gas to Western Europe (Energy Policy 6/1994). The plan is to build two parallel 58" pipelines from Torzhok - near Moscow - via Belarus and Poland to Berlin in Germany. Fully developed the export lines will have a capacity of 65.7 BCM annually, with total costs estimated at $6.7 billion[24] for the distance from Torzhok to the German border[25]. The European Union considers this project to be highly

[23] Cubic meters used in this subsection are of the smaller standard normally used by FSU. A 'FSU cubic meter' is about 6.9 percent smaller than a 'European cubic meter'.

[24] Gazprom (1994), *Proekt Yamal-Evropa,* cited in Jonathan Stern (1995), p 24.

[25] The protocol between Russia and Poland foresees flow start in 1996 with build up to 32.3 BCM in 1999, 62.7 BCM in 2005 and 65.7 BCM in 2010. From these volumes 29.3, 38.4 and 50.2 BCM are anticipated delivered at the German border in 1999, 2000 and 2003 respectively. *Source*: Stern (1995) (who refers to *World Gas Intelligence, 28 April, 1995)* pp. 62 and 71.

important and has included it on the list of investments that may receive co-financial support under the PHARE programme.[26]

The new export alternative will help Russia to successfully meet several challenges. First, it expands export capacity to the West European markets, where Russia has ambitious plans to increase its sales. Second, the project will reduce the unpleasant dependency on single transit countries. By increasing the number of alternative export routes, Russia improves its bargaining power towards these countries, and is enabled to take a firmer stand in future disputes on tariffs and other transit conditions. Third, part of the trunk line capacity may be used to serve markets along the line. This last outcome is demonstrated by the fact that Poland, as part of the agreement, is given option to purchase up to 14 BCM of gas annually.

At Torzhok it is more undetermined from which fields the export gas shall be supplied. An ambitious plan is to take gas from the Yamal Peninsula in North Russia. This will require new fields to be developed in hostile and environmentally fragile areas with no existing infrastructure for gas transportation. Gazprom estimates costs of a complete Yamal solution with an annual capacity of 83 BCM, to around $32-34 billions[24]. Some $12 billion is required to expand existing pipeline capacity from Ukhta to Torzhok. The remaining $20-22 billion will be spent in fairly equal shares on field development and to establish virgin transport capacity to Ukhta. Several analysts emphasise that the Yamal project, if realised, will substantially increase FSU unit costs of natural gas extraction and transportation. J.D. Grace (OGJ, 13 Feb. 1995) has estimated unit cost of Yamal gas to be from two to six times higher than costs incurred by further developments in the current gas province in West Siberia (i.e. Urengoy I & II, Yamburg I & II and Zapolyarnoye). According to Grace, even the offshore Shtokmanovskoye field in the Barents Sea presents a significantly less expensive alternative.

The cardinal economic key to the future of Yamal gas appears to be the development in natural gas consumption, in particular the domestic FSU consumption. Should domestic consumption and gas exports expand rapidly - as projected by Gazprom - an early development of the Yamal area may be necessary. The likelihood of a such scenario is however strongly questioned by Jonathan Stern (1995) and his view is supported by the strong and persistent decline in FSU consumption since 1991. According to Stern there are many reasons for the decline seen to continue as the process of transformation from plan to market economy progresses. He does not expect any new growth in domestic Russian gas consumption till after the turn of the century. His projections for the Russian market indicate that gas consumption in 2000 will be in the range of 300 to 340 BCM. This is around 100 BCM below Gazprom estimates and even 17 to 5 percent below the actual level (1994). Furthermore, it is difficult to see how the trend of declining gas consumption shall be avoided in other major FSU members, like Ukraine and Belarus.

If the 'Stern'-scenario is realised there will be no need for Yamal gas before 2010. On the contrary, a substantial surplus gas supply from already developed gas regions will be available for export during the next decade. Even if Russian production capacity should run short, an additional supply of up to 80 BCM can probably more economically be covered through increased production in Turkmenistan and Kazakhstan or by development of the somewhat

[26] PHARE is an EU programme aimed at improving infrastructure in Central and Eastern Europe. In co-finance with loans from international financial institutions, projects supported under the programme may receive a support that covers up to 25% of investment costs.

less costly Shtokmanovskoye field. Only if total consumption to be served by FSU increases 25 percent compared to the 1994 level, may the Yamal development be needed by 2010. Although Stern considers this last scenario to be quite unlikely, he is prudent not to rule out the Yamal project. He particularly emphasises that Gazprom is strongly rooted in the former Soviet plan economy, and still tends to favour 'mega-projects'. Combined with a strategic interest in opening a new and exciting petroleum province, this attitude may contribute to a decision that overrules simple economic considerations. Formal and practical restrictions to foreign investments in less costly developments may also work in the same direction.

3.4.6 LNG shipments as key to petroleum developments in North Russia?

Several of the vast petroleum fields discovered in north Russia are located offshore or in areas close to the coasts. Product exports on ships have thus been considered as a possible alternative to long distance and extremely expensive pipeline developments. Feasibility studies have indicated that reinforced product tankers with some ice-breaker assistance, may sail these part year ice covered waters on a regular basis, even as far east as to the Yamal peninsula (i.e. Kværner, 1995). Should a sea-bound solution for natural gas exports be chosen, it will necessitate the development of LNG-facilities and a safe loading harbour.

At the Shtokmanovskoye field, which is a giant gas field located at deep waters (320 meters) in the Barents Sea north of Kola, LNG has been considered as one of the possible export solutions. So far no final decision has been taken. It is generally accepted that foreign technology and assistance will be needed to develop this field. However, the project development has been precluded several years by 'institutional/political problems', which basically meant that Gazprom was dissatisfied with its influence in the initial joint venture arrangement. Subsequent to the Rosshelf-Gazprom consortium having now been awarded the rights to develop the field, co-operation with the original foreign joint venture partners has been resumed. Nevertheless, it remains to be seen when the field development will start and whether a LNG solution will be preferred. If the field is developed for an annual gas production in the range from 50 to 125 BCM, which is quite likely, the export solution will almost certainly be a pipeline.

LNG may perhaps appear as a more realistic export alternative for gas from petroleum provinces further east, in the Kara Sea or at the Yamal Peninsula. A LNG based solution for Yamal gas production is currently being studied by VNIIGAZ (Gritsenko, Odishario and Izolov, 1995). The preliminary conclusions, presented at an INSROP symposium, are optimistic about the competitiveness of LNG towards alternative pipeline solutions. However, it is not likely that a sea-bound solution will be chosen unless a full scale development of the gas giants in the Yamal area is postponed till well after 2010. Any major gas development in the area (50 BCM annually or more) will almost certainly be equipped with a land-based export solution, and thus probably exclude any parallel sea-wise gas transportation.

LNG may still be an option for transport of associated gas from possible oil-field developments in northern Russia. In this case oil export facilities - possibly comprising an export harbour - must be included in the developments. Necessary LNG equipment may thus be attached to the system at significantly lower specific costs than in the case of a pure natural gas development. Stable gas feed with such a solution may be secured by additional development of one (or a few minor) gas fields in the area.

The political problems related to the organisation of ownership and control in the Shtokmanovskoye project shoul be carefully noted. The conflict clearly demonstrated that it will be difficult to exclude Gazprom from control in any development that includes significant gas exports out of the FSU. At the political level Gazprom will easily find support for a co-ordinated gas sales strategy to avoid Russian gas-to-gas competition, at least as long as the import markets are not deregulated. On the other hand, Gazprom may for several reasons be interested in a co-operation on a LNG solution for northern gas. One is that it will open a new export channel and further reduce dependency on existing transit countries. Furthermore, it will present a new point of entrance to the most distant European markets in Belgium, France and possibly at the Iberian Peninsula.

3.5 Security of supply and risk handling strategies.

In natural gas developments producers as well consumers are exposed to substantial risks. Gas producers must learn to handle uncertainties in exploration, in resource estimation, in costs of field and transport system developments, and in assessing the market potential. The typical gas developments of the somewhat distant producers like Norway and FSU exhibit strong economies of scale. Such projects normally comprise a complicated structure of large and expensive field developments and transport systems. The investment decision will thus always involve a substantial capital exposure.

On the other hand, also gas distributors and consumers expose themselves through investments in local transportation systems and in gas-adapted equipment. Like the capital outlays of producers, a large part of consumer investments will be dedicated to gas, and should the market fail, this capital has a very low alternative value. Hence, even if producers and consumers oppose each other on the price topic, their destinies are strongly interrelated. Both have a strong common interest in a stable and predictable gas market: A producer who abuses market power in the short term, will soon see consumers leave for other suppliers or alternate fuels, thus undermining its long term gas sales potential. On the other hand, if purchasers squeeze suppliers too hard, future supply may be threatened by lack of new investments. The recognition of this mutual dependence has frequently materialised in various risk share agreements in the gas sector.

But even if all rational agents in the gas business should recognise the strong common interests of consumers and producers, there will still be room for worries and strategic adaptations. Particularly when gas is produced in one country and consumed in another, it is typical for the importing country to worry about the security of supply. Gas is energy and energy is a strategic commodity. In this perspective economic as well as political consequences of sudden cutbacks in deliveries will be considered. For convenience we may distinguish four different kinds of risks each of which should be addressed in somewhat different ways. These are:

- resource risk
- technical risk
- market risk, and
- political risk.

The first category - *resource risk* - refers to the commercially available gas volumes. In today's Europe this is not a predominant issue. Vast gas reserves are available, particularly in the FSU and Northern Africa, but also as '*domestic*' gas inside Europe. In a longer perspective even gas reserves in the Middle East may be connected to the European networks. This topic is therefore not of much interest within the scope of this study, and is thus not given any further attention here.

3.5.1 Technical risks.

Accidents, such as explosions and blowouts, or unscheduled shutdowns for imminent repair and maintenance, may cause significant unexpected reductions in the gas supply. This would be the prototype of events related to technical risk. But the concept may be broadened to also cover risks in relation to strikes and similar conflicts of limited duration. A convenient definition could thus be that technical risks are risks related to all kinds of supply-disrupting events that take place against the will of national authorities, but which do not threaten the existing political structure and institutions.

Frequent 'technical events' in a production country influence the credibility of the country as supplier. Purchasers will start to worry about the risks of interruption in deliveries. As a micro-level consequence, consumers will be inclined to pay a premium for a more secure energy supply. This may be attained either by selecting another supplier or by choosing an alternate kind of energy or a dual fuel solution. Such strategies will increase the average cost of energy. The cost increase will be shared between the consumer, who pays a higher energy price, and the unfortunate producer, who gets a lower return on sales.

At the macro level, both producers and consumers may address technical risks in several ways. For the producer one way is to minimise supply repercussions of accidents by dividing activities among several separate production and transport systems. In case of simple accidents only limited parts of production and supply will then be affected. This will not, however, help to avoid the problems of a full strike in the natural gas sector. Some countries have thus created special legal instruments to handle such situations. One example is the '*Compulsory wage commission*' in Norway, which has frequently been activated to terminate strikes in the petroleum sector.

In consumer countries the challenges of technical risks may be met by both technical and contractual measures. One solution is to build redundancy into the network systems. This may for instance be accomplished by demanding that all supply channels guarantee a certain amount of spare capacity that can immediately be made available in case of failure in another channel. Storage facilities could alternatively be constructed as an insurance against temporary cutbacks in supply. Which of the alternatives that is best will be a question of economic as well as practical considerations.

On the contractual level, the growing integration of the European gas market has significantly increased the potential for diversifying the source of supply. Such diversification may either be accomplished by transmission companies or by direct governmental involvement. The typical, and probably less costly solution, is to diversify the general supply and thereby reduce the effects of cut backs from a single supplier. An alternative or a complementary solution is to contract backup deliveries from other suppliers in case of cutbacks from one of the sources.

This solution may be costly to accomplish for a single consumer country. On the other hand, the producers should have a common interest in developing mutual agreements among themselves that guarantee backup deliveries in case of technical problems. Such agreements will affect the risk structure in a way that positively stimulates the willingness to use, and willingness to pay for, natural gas.

For transmission companies, the introduction of contracts with breakable deliveries is a viable measure to reduce own exposure in case of supply shortages[27]. The purpose of this kind of contracts is to allow consumers to select between secure deliveries at high cost and more risky gas supply at a lower price. For consumers who can alternate between various energy sources, this may be an attractive alternative. In case of supply shortage the differentiated contracts will provide transmission companies with a priority list for the rationing of the scarce resource.

Technical risk is an appropriate topic in relation to possible LNG supplies from northern Russia. Such shipments would represent a further division of Russian transport alternatives and thus imply a relative reduction in the possible negative consequences of severe accidents along the current transport systems. Also in the case of certain strikes and other politically unauthorised obstructions to supply, a northern gas route would represent an advantage. However, the regularity of Russian gas deliveries to Europe has so far been very good. On the other hand, the apparent gradual deterioration in the internal economic situation may result in a parallel degradation in the standard of delivery. In that respect a LNG solution with substantial foreign technical and commercial support, could be valued by the gas markets. The crucial question is if the acknowledged risk reduction is sufficiently large to accomplish a significant increase in European willingness to buy and pay for Russian gas. The answer is not straightforward, but as long as the profound political and economic problems of the Russian society remain unsolved, it is likely that the general fear of a too strong dependence on Russian gas supplies will persist in western Europe.

3.5.2 Market risk.

With market risk we here mean the exposure of gas consumers to exploitation by suppliers' possible application of market power. In this case, the monopolist (or oligopolists) would not act to a given market price, but also consider the influence of own sales on the gas price. Offered gas volumes will thus be selected at the level where marginal income from selling an extra unit equals marginal cost of producing it. As a result, traded volumes will be lower and the price higher than in a free market situation. The monopolist (oligopolists) will collect an extraordinary profit.

The potential for application of market power depends on the number and relative size of suppliers in each sub market, and on the price of substitutes. In the European gas markets the free hand of gas producers is fairly restricted as many customers may easily choose an alternative source of energy. Thus, in the current situation the market power of external gas producers should not be a matter of particularly high priority. A more important topic in relation to market efficiency, is probably the internal organisation of European gas markets

[27] This is not only related to technical risks in supply, but also applies to the challenges related to seasonally and climatically generated variations in demand. The introduction of breakable contracts improves the possible capacity utilisation of the transmission systems.

and the position of domestic transmission and distribution companies. By combining exclusive control with the means of transportation and intimate knowledge of customers' alternative costs, the distributor may be in a position to 'confiscate' a large part of the 'consumer surplus'. This implies a redistribution of income - from purchaser to distributor - but will never threaten the stability of the natural gas market. On the contrary, it may even be claimed that this kind of price discrimination is important to provide sufficient finance for the development of transmission lines and networks.

3.5.3 Political risk.

The difference between political and technical risk can hardly be defined in a very precise manner. There is a sliding transition, and what particularly separates the two is that political risk refers to a more fundamental change in a producer's willingness or capacity to adhere to agreed supply obligations. To clarify the point, take strikes as an example: In every democracy, strikes may legally be used as an instrument to help achieve professional, and to some extent also political, goals. The exposure to ordinary working disputes in gas production, can thus conveniently be categorised as technical risk. On the other hand we would refer it to political risk if the situation in a producing country should change substantially, so that strikes and other unrest get out of control and challenge the very power of political authorities.

Today's situation in Russia as well as Algeria is characterised by political instability. Algeria is in a state of civil war and Islamic fundamentalists are violently opposing a self-nominated military government. Several European countries have demonstrated clear support for the governmental side, but the outcome of the conflict is still unpredictable. The Russian situation is far from that bad. Basic questions are here more focused on the consequences of a continued deterioration in the economic conditions. Furthermore, the new political structure that has evolved during the last years, is still not very well settled and the current landscape of parties and politicians is difficult to follow.

Both for Russia and Algeria there is a significant risk that the future situation may develop to a point where the administrative capacity to maintain gas deliveries is threatened. In Algeria we have seen examples of sabotage to the gas networks, but to our knowledge exports have so far not been affected. In Russia the risk is more related to the financing of required maintenance and upgrades in gas production and transportation, as well as to possible labour conflicts. Should Russian gas exports be constrained for such reasons, there is a chance that North Siberian LNG shipments could run unaffected. On the other hand, major labour conflicts elsewhere in the petroleum sector may easily spread to the Northern areas and could thus affect LNG activities as well.

A pre-condition for European gas importers to accept Insrop LNG as a viable instrument for diversification of internal political risks in Russia, is that the LNG solution has a risk profile that is either independent of, or negatively correlated to, that of other supply alternatives. In this perspective, the strong military concentration at Kola is an issue of special concern. It is not likely that the northern military units would be insensitive to the development of widespread unrest and crumbling political authority in the rest of Russia. Since the fall of the Soviet system, military personel have already suffered a substantial degradation in economic and social conditions. During the last years there have been signs of a growing determination in the northern units to take action in order to promote own interests. Hence, if interest groups further south chose to hamper pipeline gas exports to Europe, the military would not be blind to the potential of taking LNG-shipments hostage in a struggle for own positions. In a risk perspective this potential outcome may tighten the links from the general Russian development to the position of a northern LNG solution.

Another interesting topic with regard to political risk is the relations between Russia and Ukraine. Most Russian gas exports to Europe are currently piped through Ukraine, which itself is an important customer for Russian gas. Several disputes have occurred between the two countries; on Ukrainian payments for Russian gas, on the possession of the Crimean Peninsula, on Ukrainian return of nuclear weapons positioned on its territory, and on the division of the Black Sea branch of the former Soviet military fleet. At the moment the most critical disputes on land and military issues are either solved or the conflict level has been relaxed so that an armed confrontation between the two is unlikely.

With respect to gas, the situation is more complicated. In this field Russia, together with other FSU exporters, have tried to withhold deliveries to Ukraine in order to enforce payment. On several occasions Ukraine has responded by diverting gas in transit to Europe. The large scale export pipeline that is currently being constructed through Poland, will considerably reduce Russian exposure to this kind of intimidation and so would a north Russian LNG solution. On the other hand, according to Stern (1995), the Ukrainians have been very careful not to reduce deliveries in periods of particularly cold weather. The reason is obvious. For the development of its own economy, Ukraine is at least as dependent on good relations with Western Europe as are the Russians. Furthermore, Ukraine is itself profiting from the gas sales by the tariffs accrued on transit. To impose measures that could weaken the Russian reputation as a reliable gas supplier is therefore not a particularly good idea. The gas diversions that have taken place can probably more correctly be ascribed to necessity than to bad will. Thus, except for a situation of full confrontation, it is not likely that Ukraine will carry out any lasting or critical disruptions on Russian gas transits.

The ultimate example of political risk is the confrontation scenario. If a high conflict level should arise between a producer and one or several consumer countries, disruption in gas deliveries may be used as a weapon. The problem with this strategy is that it would probably harm the economy of the producer as least as much as it would harm the consumer country. Exploitation of this kind of power would have long term effects on the relationship of trust between the partners in the gas market. Any rational government in a producer country would thus be very reserved about resorting to this option. Even a fundamentalist regime in Algeria can make good use of incomes from gas exports. Thus, an officially approved withdrawal of gas deliveries is very unlikely to take place except in situations when war is about to break out or if a regime should choose to break its trade relations with gas consuming countries on a more permanent basis. Should such a situation arise between Russia and Europe, a scenario which currently appears very unlikely to happen, possible LNG shipments would surely be handled in the same way as piped gas exports. An Insrop LNG development would thus not help European gas consumers to differentiate away from this kind of risk.

4. NON-EUROPEAN NATURAL GAS MARKETS.

Worldwide there exist only three real regional markets where substantial quantities of natural gas are internationally traded. These are North America, Europe including Former Soviet Union (FSU) and the Far East. Within each of these regions national gas markets are interconnected by means of transportation; i.e. pipelines or LNG facilities. More than 85 percent of World gas consumption takes place within these three areas. However, between the regions connections are very weak, and with a few minor exceptions no gas trade takes place between the regions. This is basically due to the high costs involved in transporting gas over the long distances that separate the markets.

In 1994 total World gas consumption reached 1824 million tons of oil equivalent (Mtoe) (BP Energy Rev., 1995). Out of this, 44.3 percent was consumed in Europe-FSU, 34 percent in North America and 7 percent in the Far East regional market. The remaining 15 percent was national consumption of gas from own resources in countries not connected to the regional markets. The bulk of this consumption took place in the Middle East in a few South American countries and in self-supplied countries in Asia.

4.1 North America: old market with a renewed structure.

The North American natural gas market comprises of USA, Canada and Mexico. This is the oldest of the regional markets and though there have been meanwhile fluctuations, current consumption is not much different from what it was at the end of the sixties. In 1970 roughly two thirds of World gas consumption took place in this area, while its share now - due to growth elsewhere - has dropped to around one third. USA has always been the major consumer in this region and also has the most advanced market structure. In 1994 regional consumption was split by 86, 10 and 4 percent on USA, Canada and Mexico respectively. The corresponding country shares in production were 77, 19 and 4 percent.

The US market is of particular interest because of the *open access (common carriage)* system which was introduced during the last half of the eighties. This American version of the TPA principle was and still is the most extensive market reform ever applied to a natural gas market. A first step of liberalisation was already taken in 1978 with the issue of the Natural Gas Policy Act (NGPA). Until then the natural gas chain had been strongly regulated all the way from well head to end user. Responding to a growing worry about a possible supply shortage, the main content of the NGPA was a partial deregulation of wellhead prices.

In 1985 the reform was taken further with the Federal Energy Regulatory Commission (FERC) adoption of Order 436. This order instituted open access and non-discriminatory transportation and aimed at permitting downstream customers to buy gas directly from producers and to ship it through existing interstate pipelines. Problems appeared however, particularly in the handling of «take-or-pay» liabilities within the frames of the new pricing principles for transportation. Also responding to critics from a Court decision, the FERC in August 1987 adopted Order 500, which was again revised in 1990. To further eliminate market deficiencies, the FERC in May 1992 adopted Order 636, called «the restructuring order». Principal elements are (Hagen, 1994):

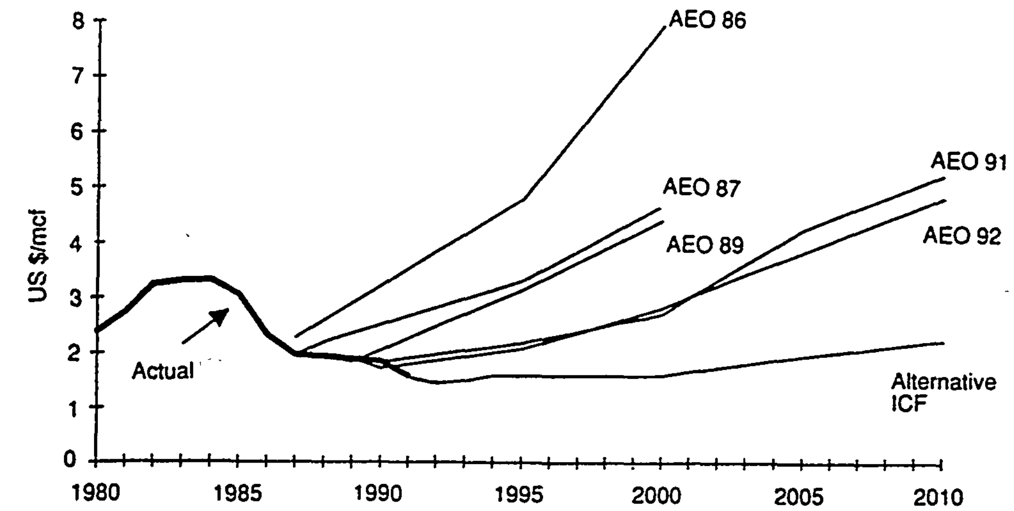
- Unbundling of transport services from sales (i.e. deprive network owners of the possibility to sell packages of gas, transport, storage etc. without separately pricing each service). The main purpose is to increase price transparency. Pipeline companies are still allowed to sell gas, but only through marketing affiliates.
- Open access is extended to include gas storage facilities. This measure aims at achieving real equality in terms of transportation between network owners and third party merchants.
- Third party shippers are permitted to release capacity held in pipelines for shorter or longer periods through a two-step auction process. The first auction is executed by the capacity holder and results turned over to pipeline operator. He posts them on «electronic boards», giving others the opportunity to make a better offer within a stipulated deadline.
- Adoption of a «Straight Fixed Variable» (SFV) rate design as the basic pricing principle for pipelines (It may be deviated from if both customers and sellers agree otherwise). SFV rates means that all fixed costs, including return on capital, are allocated to the demand charge.

By relaxing wellhead price control the NGPA in 1978 initiated a sharp increase in the price of natural gas, following the general trend in oil prices. From 1978 to 1984 prices went up from $0.91/tcf ($0.032/CM) to $2.78/tcf (0.098/CM). During this period gas consumption declined significantly, except for a temporary recovery in 1984. That was the background for the introduction of open access in 1985. The reform appears to have turned the trend in consumption. After the bottom was reached in 1986, consumption has risen steadily. In 1994 consumption was 15.9% above the 1986-level and only 5.5% beneath the peak level in 1979.

From 1985 to 1987 US natural gas prices dropped sharply, from a level of $2.69/tcf to an average wellhead price of $1.69/tcf. The decrease formed part of a general fall in petroleum prices and it is quite unclear how much of it can be ascribed to the market reform. During these two years US wholesale oil prices dropped 34% in real values. The following years, till 1990, wellhead gas prices remained fairly stable and then further decreased to $1.58/tcf in 1991. According to energy price indices from IEA (1995) wholesale gas prices recovered in 1992 and 1993, but dropped again in 1994 to below the 1991 level. Retail prices, however, have improved steadily since 1988.

The persistently low level of natural gas wellhead prices after 1987 has been contradictory to the expectations of most analysts in the field. Expectations have only slowly adapted to the realised market conditions, a fact that is vividly illustrated by the history of revised price projection shown in Figure 4.1. The downward shifts in price expectations have also substantially altered the prospects for USA as a future market for LNG shipments, a possibility that attracted much attention during the eighties. Due to relatively low reported Reserves to Production (R/P) ratios[28] it was generally assumed that the American «gas bubble» would soon burst. Today it is widely believed that the official reserves figures strongly underestimate

[28] BP 1995 issue of Statistical Review of World Energy reports a R/P ratio for North America at 12.7.



Source: DOE's *Annual Energy Outlook* (US$ 1990)[29]

Figure 4.1 Downward shifts in US natural gas price projections.

available resources and that the North American natural gas region can be self-supplied with gas far into the next century. Even though minor quantities of LNG are imported from Algeria, terminal capacities are far from fully utilised and current market prices and projections do not indicate that this situation is going to change in the near future[30].

4.2 Far East Asia: LNG shipments in a high price gas market.

The regional gas market in the Far East is very different from the North American market. This is a high price gas market where nearly all gas transportation between countries is carried out as LNG. Japan is the major consumer in the grid and has also been pioneering the market development. In 1994 the consumption, which was based completely on LNG, reached 56.8 BCM. The industrial superpower, with its tiny domestic natural resource base, imports most of its energy consumption and has no domestic gas production. Natural gas imports contribute to diversifying the energy base and the authorities already in the seventies established regulations that provided stable long term conditions for the natural gas sector to develop[31]. The first imports of LNG were shipped from Alaska in 1970. During the following years Japanese gas consumption has been increasing at a rapid rate and in 1994 reached 56.8 BCM[32]. Today the vast bulk of imports come from South East and Austral Asia with Indo-

[29] Copied from J. Kessler, B. Schillo, M. Shelby and A. Haspel: *Is natural gas really the answer? Targeting natural gas in US climate change mitigation policy.* Energy Policy 1994, vol. 22(7) pp. 623-28.
[30] A natural gas price at $1.58 per thousand cubic feet (tft) equals 5.58 US cents per cubic meter (CM) or $1.48 per Million British thermal unit (Mbtu) or $78 per ton LNG or $33 per CM LNG liquids.
[31] Economic conditions for natural gas have indirectly been assured through the protection of the national coal industry. An obligation on power stations and industry to cover a certain percentage of own demand by domestic high cost coal has contributed to a substantial increase in average coal prices. In addition oil has been virtually banned as fuel for power generation.
[32] Source: BP Review of World Gas 1995. (According to figures the average annual growth rate from 1984 has been 4.6 percent)

nesia, Malaysia, Brunei and Australia as the major suppliers. The Alaskan deliveries are continued at a low level and recently also Abu Dhabi in the Middle East has been included on the list of LNG suppliers.

During the last decade two of the new economic 'tigers', South Korea and Taiwan, have also taken up imports of LNG. South Korea started imports from Indonesia in 1986 and in 1994 the flow had reached 7.9 BCM. Taiwan, which also has a small domestic gas production, took up imports in 1990 and in 1994 reached 3 BCM. Close to 65 percent of total World LNG trade in 1994 took place in this regional market and was landed in the three countries Japan, South Korea and Taiwan.

The major regional and also world-wide supplier of LNG is Indonesia, which in 1994 exported 35 BCM natural gas as LNG. This is nearly 40 percent of total world shipments of LNG. The three other exporters in the region are only surpassed by Algeria (18 BCM). In 1994 Malaysia, Australia and Brunei exported 11, 8.5 and 7.7 BCM natural gas as LNG, while the United Arab Emirates (Abu Dhabi) came next with 4.3 BCM.

5. LNG IN INTERNATIONAL GAS TRADE.

The cost structure of LNG systems differs significantly from pipeline transportation and this difference may be of vital importance for the economic ranking of the two alternatives for a specific development. One important topic is economies of scale, which is considerably more predominant in pipeline construction than in LNG. In high pressure pipeline projects the share of fixed costs will always be high, as the amount of planning, land acquisition and even labour required, is not directly correlated to the size of the project. Hence, the marginal cost of increasing capacity is low at time of investment. Unit cost will thus fall markedly with increasing volumes. This does not mean however that economies of scale never occur in LNG systems[33], but the fall in unit cost with increasing volumes will normally not be the same size as for a pipeline alternative. Thus, even for a project where LNG is the incontestable first choice for a limited development, the two will come closer if project size is up-scaled, and with sufficiently high volumes, pipeline may surpass LNG as the preferred alternative.

Another important topic is the costs associated with distance of transportation. Contrary to pipelines, unit cost in LNG transportation is not strongly correlated to transport distance. The reason is that a fairly high share of LNG investments are fixed to the land based terminals and even the shuttle tankers will anyway spend a considerable time in harbours for loading and unloading. Marginal cost of sustaining transport capacity for an prolonged distance, is thus substantially lower than the total unit distance cost. Consequently the average unit distance cost will fall markedly with increasing distances and thereby strengthen the competitive position of LNG for long distance gas transportation.

A third topic to be mentioned is the obvious differences in risks involved. While pipelines are definitely 'putty clay' constructions, LNG developments are far more flexible. In pipeline transportation the project-specific risks are extremely dominant, and alternative value of installations may be close to nil if the project fails. For LNG on the other hand there are alternatives. If for instance the market fails in one country, shipments may be redirected to another destination. Should that not be a viable solution, the vessels may at least be sold or moved to another LNG chain. Hence the height of fall is lower for LNG than for pipelines and this difference should in principle be reflected in a lower project-acceptation threshold with regard to the expected rate of return on investment.

In the subsections below we will briefly review some available information on existing facilities and costs of LNG projects. But before doing so the preceding discussion may be summarised in the following rule of thumb:

- Compared to pipelines the economic viability of LNG *decreases* with increasing volumes and *increases* with prolonged distance and rising project-specific risks.

[33] Expansion of an existing LNG facility is substantially less expensive than a 'green grass' development, as existing infrastructure, i.e. harbours etc., may be utilised.

5.1 LNG installations, costs and contracts.

Table 5.2 and table 5.3 outline the location and size of major existing LNG facilities for liquefaction and regasification. As the figures clearly demonstrate the bulk of LNG activities has steadily moved eastwards since 1974. At the start of this period 54 percent of world-wide LNG deliveries was landed in Europe and 46 percent in Japan. Even though European LNG imports have multiplied 3.4 times till 1994, the share in total deliveries has dropped to 21 percent. The Far East, where Japan is now accompanied by South Korea and Taiwan, took 77 percent of total LNG deliveries in 1994, resulting from a 14.8 fold multiplication of imports since 1974. USA, which received the last 2 percent of deliveries in 1994, has not shown any systematic trend in LNG imports since the early eighties. Imports have moved up and down and deliveries hit the bottom with a full stop in 1987 and 'peaked' at 2.47 BCM and 2.32 BCM in 1990 and 1993. In the late seventies however, USA saw a sharp increase in LNG imports due to exploding gas prices in the domestic market. In 1979 USA imported 7.15 BCM LNG, nearly equal to the European level.

The BP annual gas publication supplies a review of LNG contracts including volumes and prices. Part of it is repeated in table 5.4. From the price figures it is easily understood why the Far Eastern market is the fastest growing. In 1993 Asian CIF prices ranged from \$3.30 to \$3.54 per MMBtu (million British thermal units), while the corresponding European prices were estimated at \$2.56 to \$2.78[34].

An IEA publication from 1994 gives a useful overview of the topics involved in natural gas transportation (IEA 1994b). The cost distribution in the LNG-chain is illustrated with an example from Belgium 1992, which is referred in table 5.1. The book also supplies some rough figures for typical investment costs in liquefaction and regasification facilities. It is emphasised that construction costs may differ widely depending on variations in physical environment, cost of land, environmental and safety regulations and labour costs. As the market for LNG facilities and liquefaction plants in particular, is very specialised and

Prices	\$/MMBtu	Cost elements	\$/MMBtu	Percent of total	Percent of 'City gate'
Average Delivered Price to Resident./Commerc. sector	6.67	Distribution Cost	2.65	40.4	67.8
Average Wholesale Price ('City gate' Price)	3.91	Transmission Cost Buyer	0.76	11.8	19.4
Border price	3.15	Shipping and re-gasification	1.00	15.2	25.6
Fob-Price	2.15	Liquefaction	0.50	7.6	12.8
		Transmission Cost Seller	0.50	7.6	29.4
Well head Price	1.15		1.15	17.5	167.8

Source: International Energy Agency (1994) *Natural Gas transportation - Organisation and Regulation*

Table 5.1 Cost distribution in the LNG chain, Belgium 1992.

[34] Price figures for 1994 are not directly comparable as BP no longer estimates CIF prices for Europe.

low-volume, costs are also strongly influenced by the actual occupation of the relatively few competent contractors. Another extremely important topic in cost is whether investments are related to a 'green grass' installation or to an additional unit in an existing plant. In the latter case costs of harbour and storage developments may be saved or substantially reduced.

With all these reservations typical costs of a liquefaction plant are indicated at:

- 'Green grass' plant with 2 units and 5 BCM annual capacity: US$ 1.4 - 2 billion
- Construction of 2 additional units: US$ 0.6 - 1 billion
- Annual operating and maintenance costs, ex. fuel, are in the region of 4% of investments.
- Fuel cost depends on gas price. About 12% of total gas intake is consumed by the plant.

Reported cost estimates for regasification plants are more confusing. The majority of sources (World Bank, Cedigaz, Total and Birnbaum Energy Research Associates) estimate costs of a plant with 5-5.5 BCM capacity at US$400-700 million. However Gaz de France deviates significantly with a cost estimate at US$ 250-500 million for an annual capacity in the range of 5-10 BCM. The IEA publication indicates that annual operating costs will represent some 2.5% of capital investment. Gas consumption in the plant may go up to 1% of incoming gas.

In another INSROP project, Kværner Masa Yard has estimated costs of a Yamal LNG development with an annual capacity of 9.9 million cubic meters (Backlund, 1995). In calculations are assumed 20 years lifetime for all facilities and 6.5 percent interest rent on capital investments. Separate figures are developed for LNG plant, storage and export facilities and transportation. Estimated costs per unit handled at full lifetime capacity utilisation are:

• LNG-plant ($1.4 billion - 2 units, 2.6 Mtoe each)	$ 11.4 / m^3 LNG =	$0.51 / MMBtu
• Storage and harbour ($710 / m^3 LNG capacity)	$ 7.8 / m^3 LNG =	$0.35 / MMBtu
• Sea transport	$10.3 / m^3 LNG =	$0.46 / MMBtu
• TOTAL	$29.5 / m^3 LNG =	$1.32 / MMBtu

Considering the current structure of the European LNG market, a new supplier must expect hard competition from established Algerian exports. In this situation it is rather optimistic to assume full capacity utilisation of all facilities from day one. With regard to the relatively high risks involved in a Yamal project, particularly in land-based installations, a 6.5 percent interest rate also appears to be a very low estimate for project-related capital costs.

5.2 LNG shipments.

By the end of 1994 the world-wide LNG fleet comprised 85 ships and according to BP another 22 vessels were under construction or planned (BP Gas Review, 1995). Total fleet capacity was around 9 million cubic meters. The bulk of the fleet - 55% of ships and 62% of capacity - was built during the decade from 1975 to 1984. About 10.5% of capacity (17 ships) is older than 20 years and consists of vessels that are substantially smaller than the newer part of the fleet. Average size of the 68 ships built after 1974 is around 117 500 cubic meters. The average for the planned newbuildings is reported at 121 386 cubic meters.

The leading construction technology is the Moss Rosenberg spherical system which is used for 42 ships and 56% of the capacity. The dominance is particularly strong in the newer part of the fleet. From a total of 16 ships built in 1990 or later, 11 ships with 75% of the capacity increase belonged to the Moss Rosenberg type. In the group of planned vessels, 17 out of 22 are of this kind.

According to BP, most European LNG contracts are agreed on fob (free on board) conditions. The three major importers, Belgium, France and Spain, together with Italy, shall have negotiated a common fob price with Algeria. Unfortunately the summary of LNG contracts in BP (table 5.4) does not give separate information on costs of transportation. However, from 1994 to 1995 BP shifted from CIF to fob price reporting for the European contracts, By comparing the two issues of the review it is thus possible to deduct estimated freight and insurance costs for the 1993 shipments. These estimates range from $0.20 to $0.42 per MMBtu - the first figure referring to Algerian LNG shipments to Spain and the latter to deliveries to France[35].

	Liquefaction	**Exports (per country) - BCM**		
EXPORTERS	**trains**	**1974**	**1984**	**1994**
Africa and Middle East				
Arzew, Algeria	15	2.93	12.15	18.17
Skikda, Algeria	6			
Marsa El Brega, Libya	4	2.52	1.11	1.48
Das Islas, Abu Dhabi - UAE	3	-	2.82	4.25
United States				
Kenaï, Alaska	2	1,22	1.37	1.57
Asia and Austral-Asia				
Blang Lancang, Indonesia	6	-	18.90	35.09
Bontang, Indonesia	6			
Bintulu, Malaysia	3	-	4.71	10.45
Lumut, Brunei	5	3.36	7.40	7.72
Withnell Bay, Australia	3	-	-	8.53
Total	53	10.03	48.00	87.80

Source: BP Review of World Gas *1995*

Table 5.2 Major LNG export terminals.

[35] These cost estimates for insurance and freight translate to $4.47 to $9.39 per cubic meter LNG or $10.54 to $22.13 per ton LNG or $7.54 to $15.83 per thousand cubic meters natural gas.

IMPORTERS	Capacity (mill. m^3 NG/day)	Imports (per country) - BCM 1974	1984	1994
Europe				
Canvey Island, UK	4.50	0.67	-	-
Zeebrügge, Belgium	17.80	-	1.66	3.98
Montoir-de-Bretagne, France	31.00	2.08	8.14	7.65
Fos-sur-Mer, France (Mediterranean)	22.00			
Huelva, Spain (close to Gibraltar)	6.30	0.92	2.09	6.43
Cartagena, Spain (Mediterranean)	2.10			
Barcelona, Spain (Mediterranean)	29.00			
Panigaglia, Italy	11.00	1.78	0.34	0.19
Marmara Ereglisi, Turkey	n/a	-	-	0.38
Total in Europe	123.70	5.45	13.23	18.63
of which north of Biscay	53.30			
United States (terminals only on the east coast)				
Everett,	8.07	-	1.03	1.47
Cove Point,	32.00			
Elba Island,	13.00			
Lake Charles, Louisiana	19.80			
Total in United States	72.87		1.03	1.47
Asia and Austral-Asia				
Young-An, Taiwan	6.00	-	-	3.00
Peyong-Taek, South Korea	41.00	-	-	7.90
Japan (A total of 13 terminals ranging from 1.20 to 100.50 m^3 NG capacity/day)	426.55	4.58	34.74	56.80
Total in Asia and Austral-Asia	473.55	4.58	34.74	67.70

Source: BP Review of World Gas *1994* and *1995*

Table 5.3 Major LNG import terminals.

Importer	exporter	start date	duration (years)	Mtpa LNG Contract	Mtpa LNG 1994	BCM NG 1994	Average fob price 1994 $/MMBtu	Average fob price 1994 $/1000 m^3 NG[1]
Belgium[2]	Algeria	1982	20	3.3	2.81	3.93	1.97	74.27
	Australia[3]	1994	-	-	0.06		n/a	n/a
France[2]	Algeria	1965	26+	0.40	5.49	7.67	1.97	74.27
	Algeria	1973	25	0.60				
	Algeria	1982	25	3.80				
	Algeria	1981	25	0.70				
Italy[2]	Algeria	1988	peaking	n/a	0.10	0.14	1.97	74.27
	Libya	1994	-	-	0.03		1.97	74.27
Spain[2]	Algeria	1975	23+6	2.80[4]	3.33	4.65	1.97	74.27
	Libya	1969	39	0.76	1.04	1.45	2.13	80.30
	Australia[3]	1993	-	-	0.38	0.53	n/a	
Turkey	Algeria	1994	-	-	0.28	0.39	2.55 [5]	
Total Europe					13.52	18.89		
USA	Algeria[6]	1988	15	0.55-0.96	1.15		1.85	92.50
	Algeria[9]	1989	20	3.3			1.27	55.00
							Average cif price 1994	
Japan[11]	6 countr.	77-93	4-20+	44.38	42.06	53,03	3.17	125.36
South Korea[12]	Indonesia	1986	2-20	5.82	5.93		3.09	126.43
Taiwan	Indonesia	1990	20	2.20	1.64	2.32	3.30	117.86
Total Asia				46.3-46.7	50.19	61.35	3.16	119.13

1) Conversion factor is referred to natural gas with en energy content of 1 MMbtu per 28 m^3 gas.
2) France, Belgium, Spain and Italy pay a common fob price for Algerian LNG.
3) Swap deal between Enagas (Spain) and Distrigas Belgium for the Belgian part of Australian gas.
4) Contract revised in 1985 to plateau at 2.8 Mtpa. Volumes will not be downgraded by agreement to take Algerian pipeline gas in 1996/97.
5) Contract based on a cif price.
6) Distrigas of Boston, Amendment 3 (which dates from December, 1988) of long standing contract; variable volume (0.55-0.96 Mtpa)
10) Trunk-line LNG, Lake Charles, Louisiana. Resumed in December 1989.
11) Japanese price and delivered volumes origins from Japan Finance Ministry. Others are estimates from Gas Matters. In 1994 Japanese LNG imports came from Alaska (2.7%), Abu Dhabi (7.5%), Australia (14.2%), Brunei (13%), Malaysia (18.7%) and Indonesia (43.9%). Most contracts are agreed for 20 years. Reported 1994 prices ranged from \$3.04 (Alaska) to \$3.25 (Indonesia) per MMBtu
12) South Korean imports also comprise some LNG from Malaysia (0.29Mt) and Brunei (0.27Mt)

Source: BP Review of World Gas *1995*

Table 5.4 Annual LNG quantities and prices.

6. LNG FROM NORTHERN RUSSIA: A SCENARIO ANALYSIS.

This section evaluates possible future LNG deliveries from the northern coasts of Russia within the framework of a scenario analysis. The work is carried out on GAS, which is a model specifically developed at the SNF for analysis of the West European natural gas markets. The model is designed to allow users to create a structural system of interconnected producers and market regions. To each producer may be connected several gas production fields with separately defined cost functions. Each of the market regions is characterised by a set of demand functions for 5 different sectors. Defined channels for gas shipments between producers and market regions are constrained by transport capacities. These channels may be LNG facilities or pipelines, but in any case the shipper must pay a fixed unit tariff that is set separately for each transport segment. A solving routine attached to the model looks for a general equilibrium solution that can satisfy all the system specifications set up by the user (Mathisen, 1984 & 1985, Fuglseth & Mathisen, 1986).

The line of action for the analysis is such that we have first developed a set of basic assumptions for the evolution of European natural gas markets till 2005. These assumptions apply to demand composition and growth in each sub-market, production capacities and costs, changes to network structure and capacities as well as the behaviour of producers (i.e. price taker or execution of market power) and consumers (i.e. import quotas). Predictions for a Base Case Scenario (BASE) with no 'Insrop' LNG supplier, are then developed for the years 2000 and 2005.

After including the 'Insrop' supplier, simulations are repeated and the resulting predictions are compared to the BASE scenario. Two alternate scenarios for 'Insrop' supply are considered. Both start with a 10 BCM capacity in 2000 and assume that all deliveries will be landed in Northern parts of Europe (i.e. north of Spain). The first alternative anticipates that the 10 BCM capacity is continued till 2005 (Small Insrop scenario - SMALL). The second alternative evaluates the consequences of a further expansion to 30 BCM capacity in 2005 (Large Insrop scenario - LARGE).

6.1 Basic assumptions and the Base Case Scenario.

Our simplified picture of the actual European gas reality is composed of 13 market regions and has 5 specifically defined producers. The market regions partly reflect single countries and partly refer to aggregated groups of neighbouring countries. For Germany we have made an exception and divided the country into two separate regions, i.e. a western and an eastern market region. Our basic producers are UK, Holland, Norway, Algeria and Russia. However, when we model the possible introduction of a North Russian LNG supplier, we have chosen to do this by adding a new producer, which we have named 'Insrop'. This implies that the LNG deliveries are handled separately from other Russian gas production.

Parameters for sector-specific demand within the market regions, are estimated from available data on prices and volumes according to a calibration procedure outlined in Thonstad (1987). The current model version is calibrated with data which originates mainly from 1992.

The following four subsections outline our basic assumptions regarding the selected market regions, the network structure and the growth perspectives. We will also briefly address some particular challenges to the application of a market approach on European natural gas trade, and describe our attempts to handle them. The fifth subsection reports results from the BASE scenario simulations.

6.1.1 Market regions and producers.

Six market regions are defined in accordance with national territories: Austria, France, Italy, Netherlands, Poland and UK[36]. Of these Netherlands and UK are also included among the five major suppliers. Five market regions consist of more than one country. Three of these are formed by simply grouping together neighbouring countries with interconnected natural gas systems: Belgium and Luxembourg, Czech and Slovak Rep., Spain and Portugal[37]. The two remaining market regions which also comprise several countries, are somewhat more complicated constructions.

The Scandinavian market region consists of Denmark, Finland and Sweden. Norway is not included on the list, partly because domestic consumption is - and probably will remain - very limited. Moreover it is unlikely that networks will ever develop in a manner that makes Norwegian consumption a natural part of a common integrated Nordic gas market. Also for the rest of Scandinavia it is problematic to speak of a common gas market. The Danish and Swedish gas markets are integrated and both supplied from Denmark. Finland on the other hand, is not yet connected to this network and all gas is supplied from FSU. A pipeline connection between Finland and Sweden may however be realised within the scope of this study. Anyway, the bundling of the three Nordic countries is convenient to maintain simplicity of the model.

The Central and South Europe market segment is created on the basis of geographical location and in many respects serves as a residual group - '*the rest of non-FSU Europe*'. It consists of Albania, Bulgaria, Former Yugoslavia, Hungary, Romania and Turkey. Relations between the individual national gas markets in the segment are occasional and fragmentary. Albania is the only country which is self-supplied with gas, but the national consumption is very low. All the other countries are net importers and the vast majority of the gas purchases are floated in by pipeline from Russia. A part of Former Yugoslavia has for several years imported small amounts of Algerian gas by pipeline via Italy, and last year also Turkey started a modest import of LNG from Algeria. Three countries in the region have a significant domestic gas production. This is in particular Romania, which in 1994 covered around 80 percent of a total national gas supply that slightly surpassed 21 BCM (BP Gas Review 1995). Hungary is the second biggest producer with a reported 1994 production of around 4.3 BCM, while Former Yugoslavia comes next with 2.7 BCM.

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[36] The Irish market is not specifically identified in this version of the GAS model. This is due to its limited size and rather isolated and self-contained position. Alternatively it may be interpreted as part of the UK market, to which it is connected by a subsea pipeline.

[37] Portugal has not yet become a natural gas user, but when it does it will probably be supplied through the Spanish network - perhaps in combination with imports of LNG.

measured in Million cubic meters	BP 1994 Production	BP 1994 Consumption	IEA / BP 1994 [3] Production	Imports	Exports	Net supply	Consumption	% of supl.
Scandinavia	4 630	6 510	4 879	3 366	920	7 325	7 191	98.2
UK	65 400	67 700	69 412	3 093	860	71 645	71 858	100.3
Holland	65 870	38 000	88 222	3 694	43 098	48 818	49 250	100.9
Belg. & Lux.		11 180		12 536	516	12 020	11 888	98.9
France	3 190	30 790	3 554	34 642	441	37 755	36 713	97.2
Germany	15 570	67 940	20 323	74 656	2 304	92 675	89 342	96.4
[1] Germany&Switz.	15 570	70 180	20 323	75 626	854	95 095	91 762	96.5
Austria	1 200	6 450	1 370	5 011		6 381	6 814	106.8
[2] Poland	3 420	9 060		5 780		9 200		98.5
[2] Czech/Slovak R.	310	11 290		12 870		13 180		85.7
[2] C.S.Europe	25 880	42 780		20 909		44 867		92.5
Italy	20 080	45 440	20 313	29 491	45	49 759	49 146	98.8
Spain/Port.	840	7 200	281	6 882		7 163	6 482	90.5
TOTAL	204 470	346 580	236 042				392 962	[4] 166.5

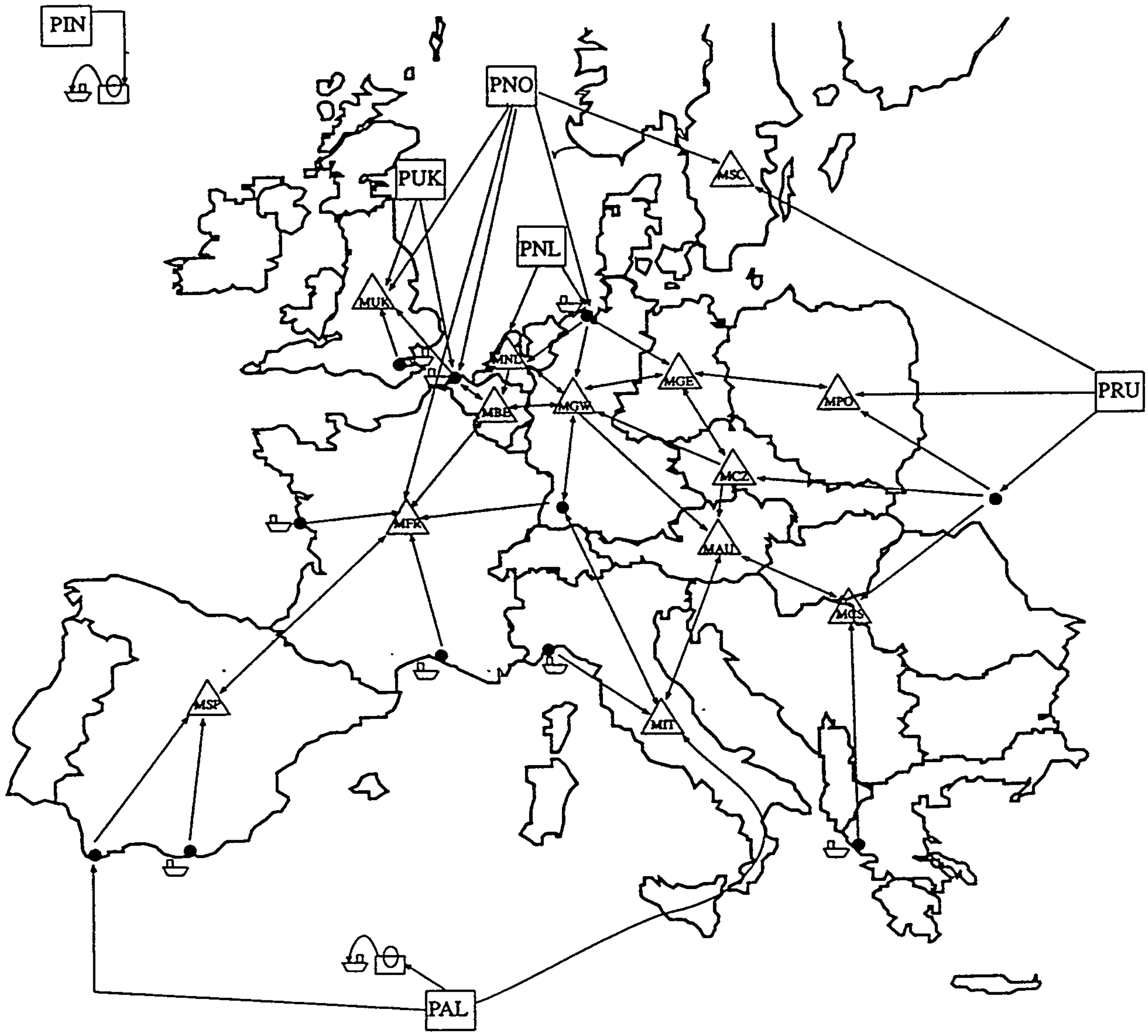
Sources: IEA, Quarterly Journal of Energy, 1995
BP Review of World Gas *1995*

Notes:
[1] Joint figures for the German and Swiss markets adjusted for trade between the two countries.
[2] Only BP figures for non-OECD members.
[3] IEA/BP refers to IEA figures for OECD members and BP data other countries.
[4] Consumption measured against 'domestic' production for the market area (included Switzerland)

Table 6.1 Natural gas balances for the market regions.

Germany is given special attention in the model. National gas demand is here split between two separate market regions - one for the western part and one for former DDR. The division is partly due to the fact that Germany is the major consumer of natural gas in Europe and hence plays a crucial role in the overall gas trade, particularly in central and northern areas. Equally important are the historical links to the near past. Until the country was reunified in 1990, the two parts had developed for 45 years under widely different economic regimes. Even though the integration of former DDR has been accelerated through radical market reforms and vast funding programs, substantial differences still remain. These factors will certainly induce significant variations between the two parts with regard to the development in natural gas consumption.

Figure 6.1 gives a schematic overview of the selected geographical model structure. Table 6.1 summarises recent natural gas consumption and production figures aggregated for each of the selected market regions. Parallel data from IEA and BP are displayed for OECD members, while figures on former East European countries are solely derived from BP. Unfortunately, also BP has now ceased to provide separate information on the two parts of Germany, and hence data shown in the table represent the whole country. For countries covered by IEA, the table includes trade data, but this information is not detailed on trade partners. Such information is provided by BP, and a summary is given in Table 2.3 above.



Production regions:	PNO	Norway	PAL	Algeria
	PUK	UK	PHL	Holland
	PRU	Russia	PIN	'Insrop'
Market regions:	MSC	Scandinavia	MGE	Eastern Germany
	MUK	UK	MGW	Western Germany
	MHL	Holland	MPO	Poland
	MBE	Belgium/Luxembourg	MFR	France
	MCZ	Czech. & Slovak Rep.	MAU	Austria
	MSP	Spain	MGW	Western Germany
	MUK	UK	MIT	Italy
	MCS	Central Southern Europe		

Figure 6.1 Geographical model structure.

As is easily observed from the table, BP and IEA figures differ substantially on several countries. The problem is particularly pronounced for some of the major continental gas consumers. For Holland the IEA production figure is 34 percent higher than the corresponding BP figure, while reported consumption deviates about 30 percent. Deviations in data for Germany are about the same size. Contrary to BP the IEA keeps a balance of in and outflows of gas and thereby secures that data are internally consistent. In BP figures the net supply and use figures may differ widely. In 1994 BP data on Germany net supply (domestic production + imports - exports) is reported at 77.4 BCM, while consumption is stated at 67.9 BCM. This leaves us with a 12 percent disparity that can only to a small degree be attributed to changes in stock levels. Such obvious inconsistencies between (and also within) data from commonly cited sources raises serious questions about the quality of information and thus creates problems for the testing of market models.

The 5 producers in the BASE case are the 5 major suppliers of gas to the European market; FSU, Holland, UK, Norway and Algeria. Some of the other European countries also have a substantial domestic gas production, but this production is not treated in the same explicit way in the model. It is registered as 'negative demand' and is distributed to the estimated demand from national market segments, before any imports take place. The simplification is justified by the fact that only very limited amounts of such gas are internationally traded.

6.1.2 Pipeline and terminal capacities.

In Continental Europe transmission capacities are continuously upgraded to handle increasing volumes and geographical extensions to the gas markets. If we take Germany as an example, such developments currently comprise the ongoing construction of the NETRA and MIDAL pipelines. Recently a connection has also been opened between France and the Spanish market. The complexity of the network structure is constantly increasing and it would be meaningless to try and make a full record of all the alternative transport routes and delivery capacities. In the scenario model the connections between European sub-markets are thus represented by a schematic and extremely simplified picture. The upgrading of capacities in this area will in most cases be subject to judgements by the model user without any clear reference to physical installations. As a guideline for our modifications, we have assumed that 'internal' networks are sufficiently upgraded to reflect enhancements made to 'external' supply capacities.

The 'external' supply channels are dealt with in further detail. Particularly the transportation systems that carry gas from Norway, FSU, Algeria and a possible additional supplier, are more directly represented by the physical installations. The rationale behind this is that new developments in such capacities will normally require vast investment programs, and upgrades will be made stepwise. Table 6.2 depicts the 'external' capacity assumptions used in the BASE scenario and the subsequent scenarios with an additional LNG supplier.

	1995	2000	2005	Comments
Russia	**106.2**	**138.0**	**179.0**	
via Ukraine	96.0	99.0	109.0	
to Czech & Slovak Rep.	70.0	75.0	80.0	- Current main entrance to Western Europe
to Poland	3.5	3.5	3.5	
to Central South Europe	22.5	25.0	25.0	- Separate pipelines to Hungary and Romania
via St. Petersburg				The Romanian line continues to Turkey.
to Scandinavia	3.7	4.5	5.0	- i.e. to Finland
via Belarus				
to Poland	6.5	35.0	65.0	
UK Interconnector				
UK to Belgium (& field con.)	.8	21.0	21.0	
Belgium to UK		10.0	10.0	
Norway	**36.5**	**70.5**	**85.0**	
Norpipe to Germany	21.5	21.5	21.0	- Connected to Statpipe
Frigg transport to UK	3.0	11.0	11.0	- 1995 capacity utilisation constrained by
Zeepipe I to Belgium	12.0	12.0	12.0	UK authorities. Assumed solution by 2000
Europipe I to Germany		12.0	12.0	- Flow start at end 1995
Frapipe to France		12.0	12.0	- Frapipe assumed to be preferred to the
Europipe II to Germany			12.0	alternative Zeepipe II solution
Scanpipe to Scandinavia		2.0	5.0	
Algeria	**34.0**	**62.0**	**70.0**	
Transmed to Italy	14.0	19.0	20.0	- 19 BCM contracted from 1996
Magreb-Europe to Spain		13.0	15.0	- Flow start planned at 1996/97. Likely delays
LNG capacity	20.0	30.0	35.0	- Included Liberian and other African LNG
Total supply capacity (ex. UK):				
Base case	176.7	270.5	334.0	
Insrop I (SMALL)		10.0	10.0	
Insrop II (LARGE)		10.0	30.0	
LNG import terminals [1]				
Belgium	5.0	5.0	5.0	
UK	1.5	1.5	1.5	
Germany		?	?	- Plans for Emshaven and Wilhelmshaven
France - Biscay	8.7	8.7	8.7	- Terminal in Bretagne
France - Mediterranean	6.2	6.2	6.2	
Spain	10.5	10.5	10.5	- 3 terminals at Huelva, Cartagena and
Italy	3.1	3.1	3.1	Barcelona
Central South Europe	0.5	4.0	6.0	- Imports to Turkey started 1994. Further
				plans for terminals in Greece and Croatia.
Changes with Insrop				
SMALL scenario				
LNG Germany		4.0	6.0	- Assumed as captive Insrop terminal.
LARGE scenario				
LNG Belgium	5.0	5.0	10.0	
LNG Germany		4.0	12.0	- Captive Insrop terminal
LNG France Biscay	8.7	8.7	10.0	

Notes:
[1] Annual capacities estimated from specified day capacities in BP Review of World Gas, *1994*

Table 6.2 Assumed natural gas supply capacities to Europe.

6.1.3 Cost assumptions.

Table 6.3 depicts the cost assumptions related to LNG in the scenario analysis. For Insrop the cost figures on liquefaction, storage and transportation are deducted from Backlund et. al. (Insrop, 1995). The original figures are scaled up by a factor of 1.2 to account for a likely gradual build up of lifted volumes as well as project specific risks and capital costs. In the Backlund project transport tariffs are referred to Rotterdam. We have used the Rotterdam price for deliveries to Germany. Prices to the other landing points are deducted by adding rough estimates for the costs of the extra distances sailed.

Algerian LNG costs are deducted from an IEA publication on natural gas transportation (1994). Figures given in that report refer to shipments to Belgium and are fairly rough estimates. Tariffs to other landing points are calculated by approximate reductions for shorter sailing distances.

Costs of landing terminal, regasification and connection to the gas networks are also deducted from the IEA report. It is set to 30 percent of the combined costs reported for transport, insurance and regasification in Belgium.

	US$ per 1000 CM Gas	US$ per 1000 CM Gas
Insrop		
Minimum unit production cost		24.1
Transport from well head	7.8	
Liquefaction	23.1	
Storage and harbour	15.8	
Fob handling cost		46.7
Shipment / Minimum CIF cost		
to Germany	20.8	91,6
to Belgium	22.5	93,4
to UK	24.2	95,0
to France	25.8	96,6
Algeria		
Minimum unit production cost		16.1
Inland transport and liquefaction	37.0	
Fob handling cost		37.0
Shipment / Minimum CIF cost		
to Spain	14.5	67.6
to Italy	16.1	69.2
to France Mediterranean	16.1	69.2
to Central South Europe	19.3	72.4
to France Biscay	24.2	77.3
to UK	25.8	78.9
to Belgium	27.4	80.5
Landing terminal / regasification et cetera.		11.3

Table 6.3 Cost assumption for LNG handling.

In the scenario analysis pipeline transmission costs are set by the model user as a specific unit tariff for each single pipe segment. Hence, in a specific segment the cost per unit of gas transmitted will be the same for every producer and regardless of the size of the transported volume. Whenever capacity constraints become effective, the available capacity is rationed among possible users (producers) according to a calculated shadow price (alternate value / potential loss of being shut out).

Production costs are calculated on field level and each gas producer may control several gas fields with different cost properties. Still, it will normally be most convenient to work with aggregates and not try to copy real physical production structures. In simulations a simple marginal cost function assures that cost per additional unit produced increases asymptotically with production. The model user controls three parameters to define and modify the cost properties. The first parameter is easily interpreted as maximum field production capacity. The second parameter decides the level of marginal cost when production is one unit away from full capacity utilisation. The third parameter modifies the gradient of the cost curve and is normally selected so that marginal cost remains fairly constant until production approaches the capacity limit and then rises sharply. Whenever several fields are attached to a single producer, the model will always apportion production among fields in order to minimise total costs.

In a survey of published European natural gas cost estimates, Dahl and Gjelsvik (1993) clearly document the difficulties related to the estimation of "correct" cost figures. Shortage of primary data on contract prices and production costs adds to the problems of allocating costs across products, as gas very often is a joint product with oil and natural gas liquids. Due to deviations in the level of reporting, Dahl and Gjelsvik also experienced problems in comparing costs across studies, and furthermore, the variations between data which should be comparable were often very high.

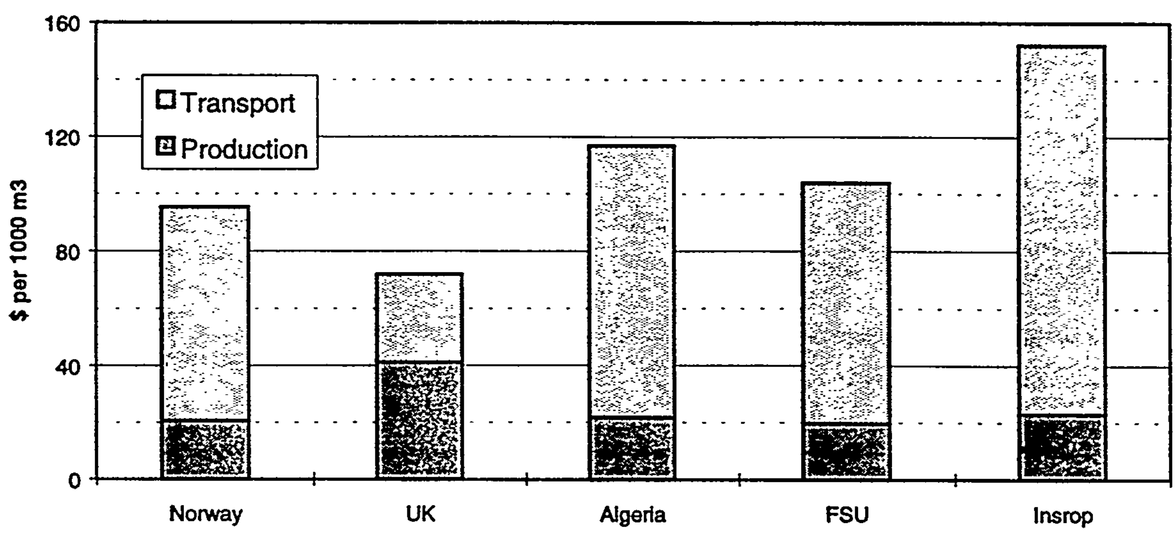


Figure 6.2 Average city gate unit costs (ref. scenario SMALL20 - see chapter 6.3).

The crucial cost figure in a market model, is the reservation price of sellers. In the very short term this price will primarily depend on variable costs, while in a longer perspective also fixed costs must be fully covered. In a medium to long term analysis, like the one conducted here, one has to decide to which degree capital costs shall be included. Thus, the estimation of cost figures will obviously be subject to considerable judgements by the model user. In Figure 6.2 the effects of cost and capacity assumptions applied in the subsequent analysis, are illustrated with reference to a specific scenario[38]. The underlying figures are calculated by dividing model estimates for total transport and production costs into total gas sales for each producer. Thus, what is stated is the average unit costs accrued in the process to produce and deliver gas at city gate.

6.1.4 Producer behaviour and market structure.

GAS allows the model user to select among three different kinds of strategic market behaviour for the producers. The alternatives, which may be set separately for each producer in every market segment, are: price taking, collusion and Nash-Cournot equilibrium. In the subsequent analysis the Nash-Cournot alternative is used with a few exceptions. In the newly deregulated UK market all producers are assumed to be price takers. In Holland, domestic production is defined as price taker, while all other suppliers are assumed to adapt according to the Nash-Cournot conditions.

The reason to choose Nash-Cournot as the preferred strategic behaviour, is that this alternative appears to give the best fit to the gas market situation currently observed in Europe. Both collusion and price taking would infer producers to concentrate gas sales. This is not what happens. Norway sells gas to France and Germany and so does Russia. Norway has also accorded deliveries to Spain and is negotiating gas sales both to Italy and to several East European countries. In the latter case Russian cost advantages should be sufficient to exclude Norwegian gas sales on competitive terms. In Italy and Spain, Norway should have severe problems to compete with Algeria, who conveys LNG as far north as Belgium. The Nash-Cournot behaviour is the only one of the available strategic market behaviours that allows the observed differentiation of supply to take place within the model.

6.1.5 Growth parameters used in projections.

Simulation of demand growth in the GAS model rests on two fundaments. One is a set of segment-specific demand parameters defined separately for each of the market regions. These parameters are prepared from available historic data on prices and volumes by the help of a specifically designed calibration procedure[39]. Normally the user will not modify any of these parameters during simulations. A new calibration of these parameters has not been possible within the limits of this study. The parameters used in the analysis are thus basically generated from 1992 data on sector demand.

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[38] SMALL20 refers to a scenario with 10 BCM of North Russian LNG shiped to the European markets in 2005.
[39] The frames of this project have not permitted a renewed calibration of the model. Current parameters are thus based on figures dating back to 1992/93. (For further details on the calibration procedure, see Thonstad (1987)).

The other fundament is a set of growth parameters that must be specified by the model user. These estimates are set separately for each market region and comprise annual growth rates for gross national product, for the number of households with gas heating, and for the use of gas in electricity production. Table 6.4 outlines the growth estimates used in subsequent model calculations.

6.1.6 Reference price for substitutes.

Possible substitutes to gas are handled in a very simplistic manner by the GAS model. The whole spectrum of available energy sources is represented by only two kinds of fuel oil; light (1% sulphur) and heavy (3.5% sulphur). The idea is that these are predominant competitors to gas and hence the quality of the model is not necessarily improved by involving further details. The two fuel oils are traded internationally in large volumes and prices adjust currently to changes in market conditions of other fuels and energy sources.

Fuel oil prices for the model calculations are given with reference to bulk barges, fob Rotterdam. Basic per ton prices used in subsequent simulations are USD 65 for heavy and USD 85 for light fuel oil. These price levels are considerably lower than the prices recently observed in the markets. With reference to Platt's Oilgram Price Report, OPEC Bulletin reported that prices for July 1995 were at USD 102 and 87 for the two fuel oils.

	1995 - 2000			2001 - 2005		
	GNP % incr.	Households % incr.	El. prod. % incr.	GNP % incr.	Households % incr.	El. prod. % incr.
Scandinavia	1) 8.0	1) 8.0	1) 70.0	2.6	3.0	20.0
UK	2.2	1.0	12.0	2.2	0.5	5.0
Holland	1.9	0.3	2.0	1.9	0.3	2.0
Belgium & Lux.	1.9	1.0	5.0	1.9	1.0	3.0
France	2.0	0.5	10.0	2.0	0.5	7.0
Germany West	3.0	1.5	5.0	2.7	1.0	3.0
Germany East	3.5	6.0	10.0	3.0	2.0	5.0
Austria	2.1	2.0	3.0	2.1	2.0	3.0
Poland	3.5	2.5	30.0	3.5	2.5	10.0
Czech. & Slovak.	3.2	2) 50.0	3.0	3.2	2) 20.0	2.0
C.S. Europe	2.0	15.0	2.0	2.8	10.0	3.0
Italy	2.3	1.0	14.0	2.3	1.0	7.0
Spain & Portugal	2.6	10.0	20.0	2.6	7.0	10.0

Notes:

1) Sector demand parameters are calibrated from data on Denmark and Sweden while the Nordic model region is later extended to include Finland. Extreme growth rates are thus used to create what is believed to be a more realistic picture of future gas demand in this region.

2) Calibration of demand parameters for former East-bloc countries is difficult due to lack of reliable data and also because of the ongoing market reforms. High estimates for growth in gas-connected households are meant to compensate for unrealistically low 'start' values.

Table 6.4 Growth estimates for the scenario analysis.

A reason for selecting lower than current prices, is that the price difference between highly refined and semi-refined oil products has been particularly small during 1994 and 1995. This situation may be due largely to an extraordinary demand for fuel oils in industry and sea transportation in a period of high economic activity. Even though there may be signs of enduring structural problems in the European refinery industry, it is likely that price differences will again increase when the economic trend turns downward.

6.1.7 Some particular challenges to the modelling.

A scenario model like GAS, will never provide a complete and true picture of a complicated structure like the European natural gas market. The model can best be understood as a simple remedy to organise certain parts of available market information. This fact implies that model results should be used with caution. The calculations rest on a series of assumptions and simplifications that may critically influence the results presented below. Some topics deserve specific attention in this respect:

- GAS assumes *third party access* (TPA). This implies that all producers are given access to topical pipeline segments on equal conditions with regard to transport tariffs and the sharing of scarce capacity. This is not a correct description of the current situation. In most European countries the transmission companies own and control the pipelines. These companies are normally in a position to execise a high degree of control over TPA for own pipelines and may also differentiate tariffs among users. The TPA assumption thus implies a more efficient solution than the one that will be realised under current conditions. As a result the scenario model tends to overestimate capacity utilisation and thus indirectly the consumption of gas.

  There are several reasons though, which may justify the assumption of TPA for the scenario analysis. One is the practical advantages of maintaining a simple model structure. This applies both to the computational challenges and to the collection of adequate data. It would be extremely expensive and difficult (not to say impossible) to accomplish satisfactory data on tariffs, capacity utilisation and other important aspects in relation to the use of each single network segment. Even with success in these matters, we have no guarantee that accurate data of the current situation would give a better approximation than TPA to the market reality 5 to 10 years ahead.

  Current trends of liberalisation in European energy markets and the initiatives of the European Union (e.g. the preparation of the energy directive), indicate a sliding development in the direction of TPA. Even if EU should not succeed in creating appropriate common legal structure in these matters, solutions for network utilisation too far removed from TPA will probably not be sustainable. Such solutions will most likely be attacked either from the development of parallel pipeline systems, or by the introduction of TPA in legal terms. Thus the TPA assumption may provide us with a better approximation to the future network reality than to the situation of today.

- GAS calculates a market solution. Hence there are no easy ways to explicitly include actually contracted gas sales. This may be considered as a substantial weakness of the model as we know that current European gas markets are typically characterised by long term contracts. To take Norway as an example, the country has already agreed large and long term gas sales contracts with most of the countries that are of particular interest in relation to an Insrop development. A likely consequence of ignoring these contracts is that GAS whould tend to overestimate the potential markets available to a new producer.

On the other hand, European energy markets may be moving in the direction of gradual integration and liberalisation. UK has already introduced the TPA principle and the former regulations on domestic gas trade - including the British Gas monopoly - have been rapidly demolished. Within a perspective of 10 to 20 years, existing contracts on gas sales for the rest of Europe will also pass through several rounds of negotiations. As far as production capacities admit, a typical aim in such negotiations will be to at least maintain the established gas volumes. To accomplish that, gas prices will have to respond to market realities at the actual point in time. The threat of newcomers and the cost of substitutes will thus lay an important part of the framework for prices also in the long term supply contracts. As to total supply and consumption, existing contracts will thus not necessarily lead us too far away from the market solution. However, accorded contracts and established supplier-wholesaler relations, will necessarily complicate the market entry for new producers. Furthermore, possible market reforms may have modified the situation substantially by the end of the period in scope (i.e. by 2005).

6.2 Basics of the BASE scenario.

Principal results of our base case simulations are reported in figure 6.3, figure 6.5 and figure 6.4 below. As may be seen from figure 6.3, the model assumes total European gas consumption to grow by 23.1 per cent from 1994 to 2000 and a further 10.5 per cent over the next 5 years. This implies average annual growth rates of respectively 3.5 and 2 per cent for the two periods. The high growth rate predicted for the first 5 years is due particularly to a series of new pipelines planned or under construction, and which will be operative by the turn of the century.

Looking back at historic data, an annual growth rate at 3.5 per cent is significantly higher than the growth rates experienced during the eighties. According to figures from BP, the average annual growth rate in European gas consumption from 1984 till 1994 was 2.2 per cent.

Compared to estimates presented by other analysts our predictions fit fairly well for Europe as a whole, but tend to be skewed in favour of West European gas consumption. Table 2.1 shows the BASE case projections together with estimates given by Cedigaz (Paris, 1994)[40].

gas volumes in BCM	OECD Europe	Central & East Europe	Total
Cedigaz projections[1)]			
for 2000	380 - 400	80 - 90	460 - 490
for 2010	440 - 470	110 - 125	550 - 595
BASE scenario projections			
for 2000	411	72	483
for 2005	452	83	535

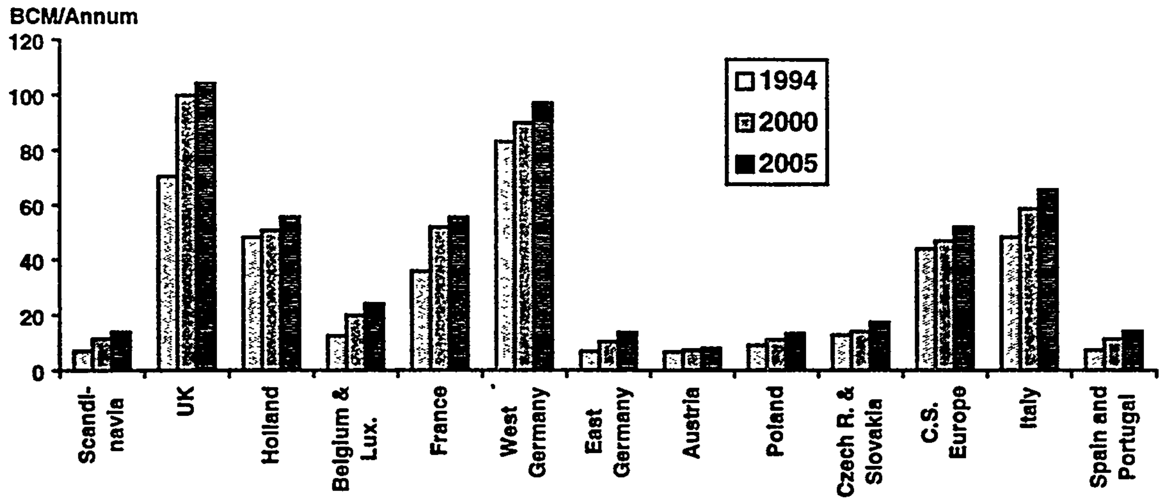
[1)] Cedigaz, Paris 1994

Table 6.5 BASE case estimates compared to Cedigaz projections.

6.2.1 Regional consumption.

For Western Europe the BASE scenario predicts a particularly rapid growth in gas consumption for the peripheral areas in Scandinavia and on the Iberian Peninsula. These regional markets are both among the most newly developed in Europe and the potential for further gas utilisation is still large. The partitioned market development in the Nordic countries was recently supported by an agreement on formalised co-operation between Gazprom and the Finnish industrial giant, Neste. For the Danish-Swedish branch the state-owned Danish gas utility company has contracted an annual gas supply of 7.4 BCM by the year 2000. According to recent estimates the company now expects demand to exceed that level by some 2 BCM. Thus the fairly limited Danish gas reserves may not be sufficiently large to keep up with the growing demand. Additional gas volumes may have to be supplied from elsewhere. The most

[40] For an overview of published projections on gas consumption, see Stern (1995), p. 83.



	Consumption (BCM)			Total % change		Annual % change	
MARKET REGION	[1] 1994	2000	2005	1995-2000	2001-2005	1995-2000	2001-2005
Scandinavia	7.1	11.4	14.0	60.6	22.8	8.2	4.2
UK	70.5	99.8	104.1	41.6	4.3	6.0	0.8
Holland	48.3	50.7	55.7	5.0	9.9	0.8	1.9
Belgium & Lux.	12.5	19.9	24.1	59.2	21.1	8.1	3.9
France	36.0	52.0	55.7	44.4	7.1	6.3	2.4
Germany West	[2] 90.0	89.7	97.0	[2] 11.2	[2] 10.8	[2] 1.8	[2] 2.1
Germany East		10.4	13.9		33.7		6.0
Austria	6.7	7.4	8.1	10.4	9.5	1.7	1.8
Poland	9.1	11.1	13.4	22.0	20.7	3.4	3.8
Czech. & Slovak.	12.9	14.1	17.5	9.3	24.1	1.5	4.4
C.S. Europe	44.0	46.9	52.0	6.6	10.9	1.1	2.1
Italy	48.2	58.7	64.6	21.8	10.1	3.3	1.9
Spain & Portugal	7.4	11.4	14.4	54.1	26.3	7.5	4.8
TOTAL	392.7	483.5	534.5	23.1	10.5	3.5	2.0

Notes:
[1] Figures are estimates deducted from IEA and BP reports
[2] Figures refer to whole Germany

Figure 6.3 Aggregate Regional Gas Consumption in the Base Case.

likely alternative appears to be imports from Norway, which is also assumed in the analysis.

In Spain and Portugal the gas market development is currently stimulated by the newly installed pipeline connection to France and by the ambitious Maghreb-Europe pipeline project. The new pipeline developments fundamentally alter the supply situation in the Iberian market, which until recently was based solely on LNG imports, primarily from Algeria.

In central parts of western Europe the highest growth rate in gas consumption is predicted for Belgium and Luxembourg. This development relates to the likely reinforcement of the Belgian position as a node for landing and further transmission and distribution of gas to the rest of North Western Europe. Deliveries are now gradually building up through the 12 BCM Zeepipe connection from the Norwegian sector. Furthermore, according to schedule the 20 (10) BCM Interconnector from Bacton in UK shall be on-line in 1997 (likely delays). A logical consequence of the Belgian position is that gas flowing through the country may always be delivered to Belgian customers at a lower cost than to more distant buyers.

Also for UK, France and Italy the model simulations indicate a fairly rapid growth in gas consumption, particularly for the period till 2000. In UK the growth predictions relate to the ongoing market liberalisation. The gradual development of a free domestic gas market has here already entailed a sharp increase in the competition between gas sellers. A corresponding decrease in spot market gas prices is now observed. According to the time schedule for deregulation - starting with sales to large customers - we have assumed that the bulk of new gas consumption in UK will appear in the electricity sector. In addition, there are indications that the use of gas in power generation was formerly constrained by informal agreements between British Gas and the coal industry. As BG is now rapidly losing its dominant position, the effects of such agreements will disappear and the substitution of coal in the electricity sector may thus be accelerated.

The intuition behind the projected development in French gas consumption is supported by the large new supply contracts accorded with Norway under the Troll agreement. Capacity limits in pipeline supply to the French market are already expanded by the Zeepipe connection to Belgium. However, to handle all the contracted gas sales from Norway, an additional pipeline will be needed from about the turn of the century. The scenario analysis assumes that the Norwegian obligations will be covered by a new 12 BCM trunk line directly to the Channel coast of France. We also believe that the new Polish gas channel together with network developments in Germany, will significantly increase Russian export capacities. Furthermore, published data on French LNG import terminals (BP, 1994) indicates a substantial spare capacity at current import levels. What may be questioned though, is the timing of the gas expansion. Some of the consumption build up that we have indicated by 2000, may possibly be postponed to the period from 2000 to 2005.

For Italy it is assumed that gas consumption in electricity production will increase sharply. According to announcements from the ENI daughter, ENEL[41], the company intends to convert most of its base load electricity production to gas. Following a realisation of this policy, the gas consumption in Italian power generation alone, will reach 17 - 20 BCM in 2000.

Estimated growth in gas consumption is fairly moderate for the remaining countries in north west continental Europe (that is in Germany, Holland and Austria). It is indicated average annual increases in the range from 0.8 to 1.8 per cent for the first five years, and 1.8 to 2.1 per cent from 2000 to 2005. For Germany the predicted growth in gas consumption is considerably higher for the former DDR than for the rest of the country. In Holland the maturity of the market together with the self imposed restrictions on domestic gas production contributes to the moderate growth rate.

In East Europe, the highest growth rates are predicted for Poland and the Czech and Slovak Republics. In the mixed Central South Region a likely combination of economic problems, increasing energy efficiency and abandonment of inefficient industry, may entail a decline in total energy consumption. As to gas, the simulations indicate a particularly slow growth rate for the next few years. After 2000 it is assumed that some of the major problems related to the economic transformations in Eastern Europe will have been overcome. Together with

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[41] Euroil, November 1993, *with reference to Cedigaz.*

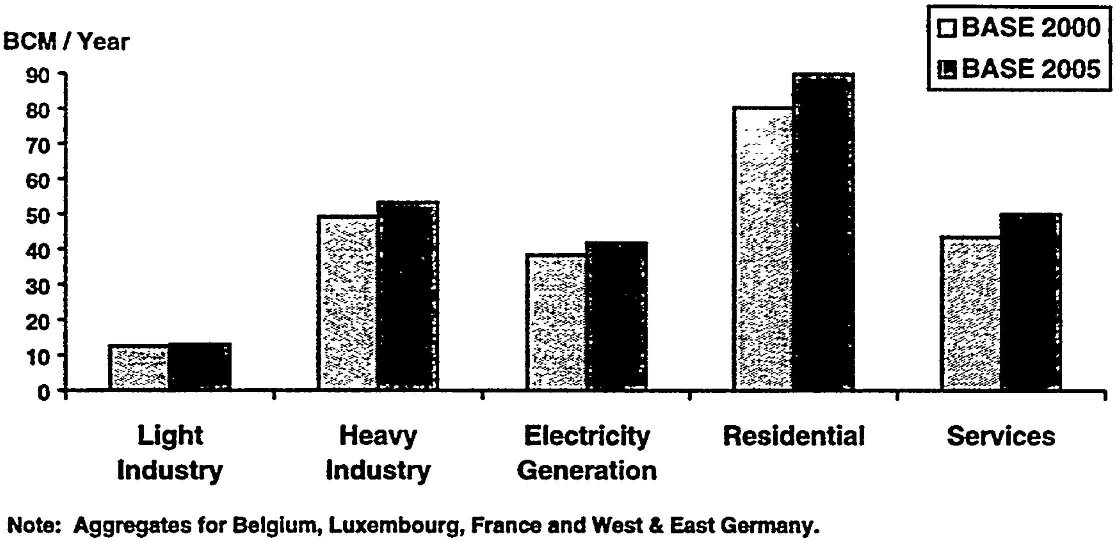

Figure 6.4 Aggregate Gas Consumption in Principal Insrop Markets by sector.

substitution of coal in several applications, revitalised economies may thus contribute to higher growth rates for gas consumption in the South as well as in Poland and the Czech and Slovak Republics.

Figure 6.4 illustrates aggregate sector distribution of gas usage for Belgium, Luxembourg, France and Germany. These are the countries believed to be the core area for possible 'Insrop' LNG exports to Europe. According to base case model projections for this area, the industrial share in gas consumption will decline from 27.6 to 26.7 per cent from 2000 to 2005. Furthermore, the share of gas delivered to electricity production will drop slightly, from 17.2 to 16.8 per cent during the period. On the other hand, residential as well as commercial gas consumption will improve its relative position, from a combined share at 55.2 per cent in 2000 to 56.4 per cent in 2005.

Estimated sector shares for the selected area differ substantially from the corresponding figures for Europe as a whole. The deviation is particularly large in electricity generation with a share of gas used for this application about 10 per cent lower than in total Europe. This difference is balanced by a correspondingly larger share of gas consumed by the residential and commercial sector. The background for the deviation is found in the French market where gas usage in power generation is virtually non-existent.

6.2.2 Regional production.

Figure 6.5 depicts predicted gas supply from the 5 major producers. According to the illustration the most radical relative expansion is expected for Norway, where the gas production is predicted to increase from 25.8 to 63 BCM from 1994 to 2000 and further to 76 BCM by 2005. UK production will expand from 68 BCM to 87 BCM in 2000 and then remain fairly stable till 2005. Holland is expected to stabilise its production at about 85 BCM annually, which is slightly below the 1994 level. For Algeria the simulations indicate an increase in supply from about 30 BCM today via 52 to 58 BCM in 2005. Russian gas supply is predicted to grow from 98.7 BCM to 124 BCM in 2000 and 155 BCM in 2005.

For Norway and FSU the supply expansions are strongly related to ongoing and planned capacity upgrades. In the case of Norway the expansions are also largely affirmed by contracts on long term gas deliveries to Continental Europe. For Holland and UK the indicated production levels originates from more contestable assumptions. In the case of Holland we have chosen to believe that the political volume constraints on domestic production are maintained. For UK the Wood Mackenzie (1995) report on the Interconnector, indicated that UK gas reserves may have the potential to maintain a 10 years' production level above 100 BCM, starting from 2000. However, the analysts call in question the commercial basis for a realisation of this large production alternative. Thus, in the analysis the production is assumed to stabilise at a significantly lower level.

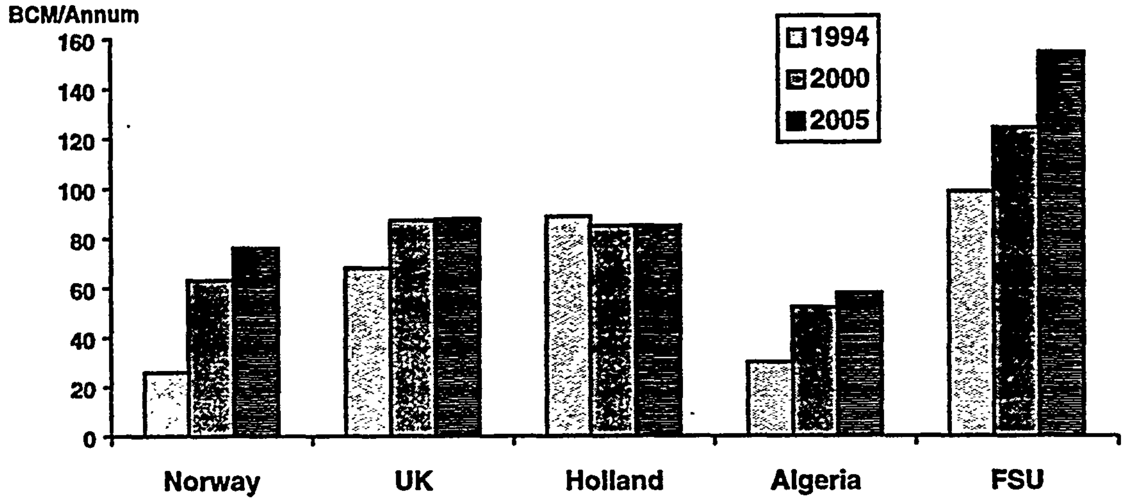

Figure 6.5 Gas Sales from the Major Producers in the Base Case.

6.3 New LNG deliveries to North West Europe.

The analysis includes two different scenarios for introduction of Russian LNG into the European gas markets, SMALL and LARGE. Both assume an 'Insrop' delivery capacity in 2000 at 10 BCM. The SMALL scenario maintains this capacity to 2005, while LARGE assumes a further increase to 30 BCM at that time.

Simulations ignore all kinds of information about contracted gas sales and thus indirectly assume all producers to compete on equal terms in each of the regional markets. What principally defines gas deliveries are demand relations on one hand and production and transport capacities and costs together with the behaviour of producers, on the other. Basic assumptions regarding transport capacities in the major import channels are outlined in table 6.2. Detailed cost assumptions for LNG are given in table 6.3.

6.3.1 Pattern of Insrop supply.

figure 6.6 illustrates the modelled pattern of LNG supplies from Insrop to the European market regions in 2000 and 2005. Not surprisingly four of the regions, which are closely related to LNG landing terminals, represent a core area for Insrop gas sales. These are the two German markets, France and Belgium & Luxembourg. With the small scenarios (SMALL20 and SMALL25), this core area absorbs 90 and 99 per cent respectively of the totally 10 BCM gas supplied from Insrop. In SMALL20 France is the major importer with 42 per cent of total Insrop deliveries. Germany takes 31 per cent and Belgium 17. In SMALL25 Germany takes 50.5 per cent of total supply, while French and Belgian shares are 26.7 and 21.8 per cent. With the large scenario (LARGE25) the dominance of the core area is reduced to 85 per cent. Here Germany is still the major partner with 43.3 per cent, while France and Belgium take 29.1 and 13.1 per cent respectively. Total export with this scenario is 26.8 BCM.

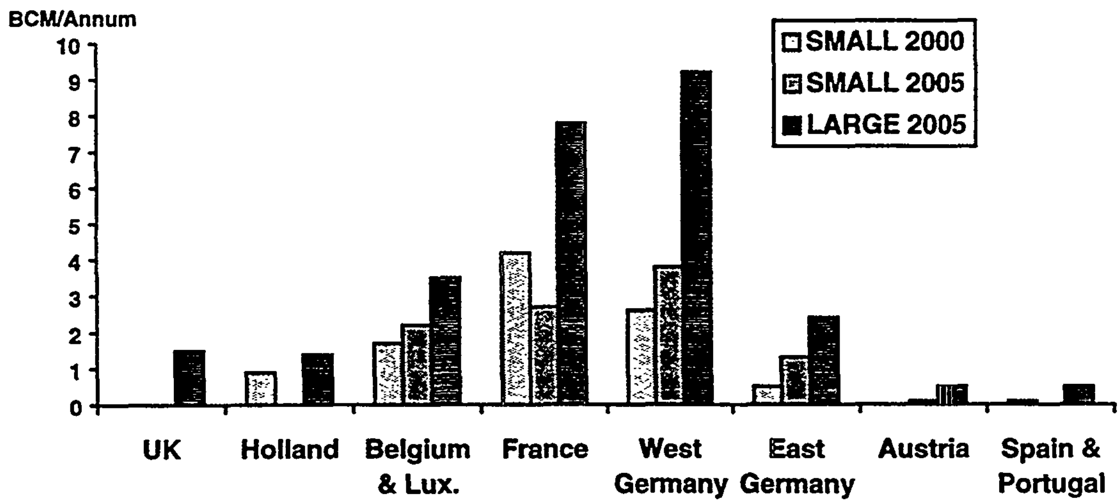

Figure 6.6 Regional Distribution of Insrop Gas Sales.

With the small scenarios, deliveries outside the core area are very limited, particularly in 2005, when the only «external» delivery is a 0.1 BCM gas sale to Austria. In 2000, Holland is the major importer outside the core area with 0.9 BCM, while Spain & Portugal takes 0.1 BCM. In LARGE25, deliveries are more dispersed and in this case Insrop also takes over former Algerian deliveries of 1.5 BCM to UK. Export to Holland is increased to 1.4 BCM, while Austria and Spain & Portugal will take 0.5 BCM each.

Compared to the base scenario, the new Insrop volumes find their way to the markets partly as increase to total supply and partly to the displacement of deliveries from other sources. Of the 10 BCM LNG supplied from Insrop in 2000 under the small scenario, 78 per cent is reflected in increased total gas consumption. In 2005 the corresponding percentage is 72. The relative balance between volume increase and displacement is about the same with the large scenario. It should however be noted, that deliveries under this last scenario do not employ the full transport capacity defined for Insrop for 2005.

The major volume loser to Insrop is of course Algeria, who will face the newcomer directly at the capacity constrained LNG landing terminals. A 10 BCM Insrop solution will reduce Algerian gas sales to Europe by 3.3 per cent in 2000 and 3.5 per cent in 2005, compared to the base case. With the larger Insrop alternative, the reduction in Algerian exports comes close to 10 per cent. For the other suppliers the introduction of Insrop has only minor influence on delivered volumes. Figure 6.7 depicts the results.

According to simulations, the small volume Insrop alternative is easily absorbed by the markets both in 2000 and 2005. The 30 BCM capacity, on the other hand, appears to be more arduous to fit in without altering our basic assumptions. In scenario LARGE25, total Insrop sales are projected at 26.8 BCM. Aggregate capacity at available landing terminals is set at 33.5 BCM. The German terminal, which is presumed captive to Insrop, covers 35.8 per cent of this capacity. For access to the remaining 21.5 BCM landing capacity, located in UK (1.5), France Loire (10) and Belgium (10), Insrop must compete with Algeria.

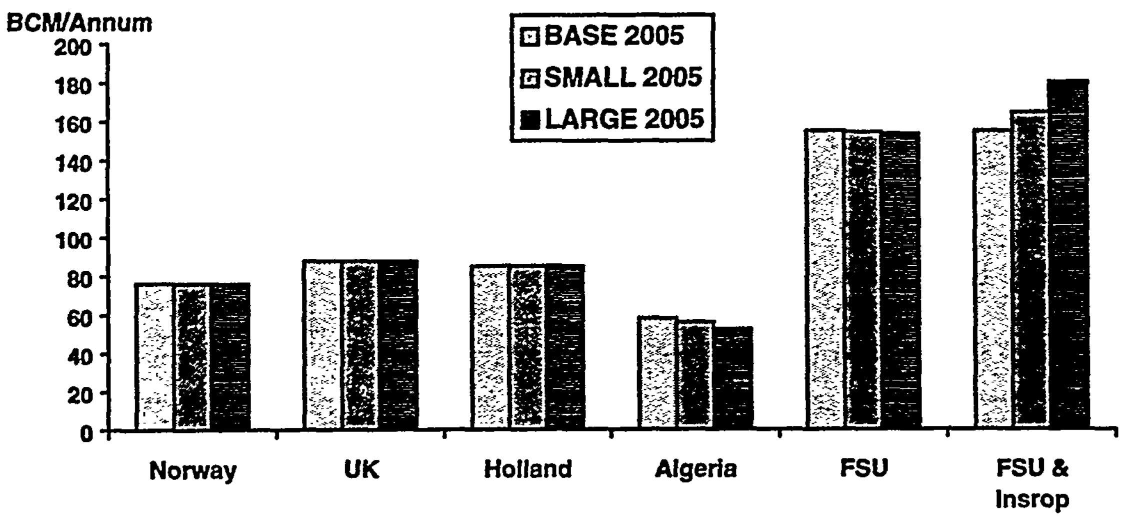

Figure 6.7 Altered Gas Sales from the Major Producers with Insrop.

Full employment of the large volume Insrop capacity may be attained in several ways by modifying some of the basic assumptions. One alternative is to increase the capacity of the German terminal. In this case Insrop deliveries expand straight to the capacity limit with the delivery increase apportioned among Holland, Belgium, Austria and the two German market regions, while deliveries to UK, France and Spain remain unchanged.

Another way to fill capacity is to assume price taking behaviour for the LNG suppliers in the French market. When only Insrop acts as price taker, its deliveries to France increase by 92 per cent while deliveries to all other destinations decrease. If also Algeria is price taker, the increase in Insrop supply to France is slightly below 80 per cent compared to the base case.

To check stability of results we have rerun simulations for the LARGE25 scenario with altered values on several parameters. A 50% reduction in Insrop minimum marginal cost of production, infers a 1.1 BCM increase in total Insrop gas deliveries, and is countered by a similar reduction in Algerian exports. Not surprisingly the bulk of the market share transfer takes place in France. Volumes of the other producers are not significantly affected.

A similar result with an opposite sign is observed when the tariff on Insrop shipments is increased by 1 US cent per cubic meter gas. In this case total Insrop deliveries contract to 24.2 BCM, a decrease of close to 10 per cent compared to LARGE25. On the continent the inverse transfers of market shares between Insrop and Algeria are about the same absolute size as in the former case. The only major difference is seen in UK. Here the whole volume of LNG deliveries is shifted over from Insrop to Algeria.

The effect of a price increase on gas substitutes was also tested. The price per ton of light fuel oil was raised from $85 to $100 and for heavy fuel oil from $65 to $85. The effect on total Insrop deliveries was only marginal, though a modest internal transfer of sales volumes took place. A minor increase in deliveries to Belgium was counterbalanced by reductions in sales to Holland and East Germany. Algerian and piped Russian gas exports were more directly affected. Here the fuel price increases induced a volume increase of 5.6 per cent (3 BCM) for the former and 3.2 per cent (5 BCM) for the latter. Also UK production was up 0.7 per cent, while Dutch and Norwegian production remained unchanged. Total European gas consumption expanded 1.6 per cent compared to LARGE25. Consumption increased in all countries except France and Italy. In those two countries the rise in gas usage in electricity production was more than counterbalanced by reductions in other sectors.

6.3.2 Economic implications of Insrop LNG export to Europe.

A North Russian LNG development is unlikely to be realised unless some gas sales can be contracted in advance. In this respect, a possible go ahead for the project will not be an exclusively Russian decision to take. On the other hand Russia holds a veto. If the development is not considered to serve Russian interests it will never take place. Thus, the economic contribution to total Russian gas sales will be a matter of particular interest. Figure 6.8 illustrates how the introduction of the two different Insrop volumes will influence projected contribution from gas sales to the major producers in 2005.

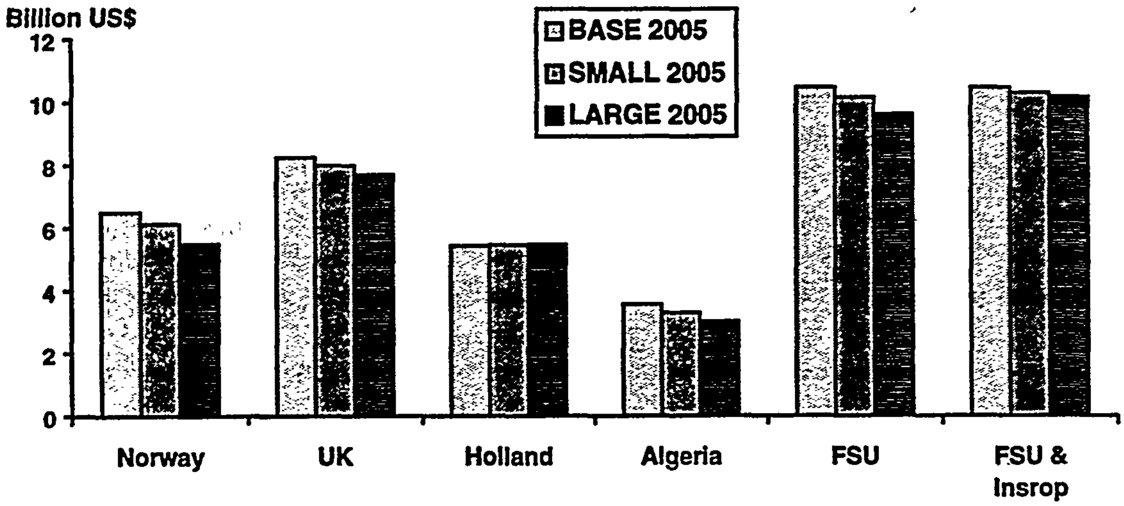

Figure 6.8 Altered Contribution from Gas Sales with Insrop.

The figure clearly indicates that the contributions from gas sales to all major producers, except Holland[42], are negatively influenced by the introduction of a new producer. This is a logical consequence of increased supply in a commodity market where demand remains unaltered. The price effects of this shift in the position of the "market cross" is illustrated in figure 6.9.

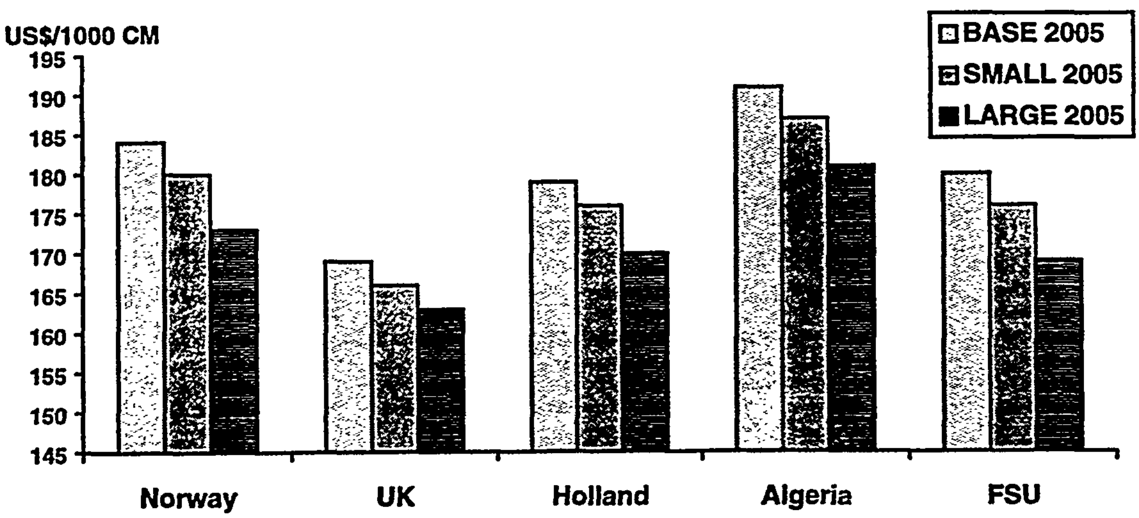

Figure 6.9 Average City Gate Gas Prices realised by the Major Producers.

[42] The case of Holland is difficult to explain and may be due to erroneous model calculation of transport costs. Figure 5.6 showed that Dutch gas production is not altered by new Insrop gas deliveries. It is thus logical that the supply expansion should reduce Dutch incomes from gas sales due to negative price effects. This effect is also projected by the model and is reflected in figure 5.8. But in the calculation of contribution, the model counters decreasing incomes with equal reductions in costs of transport. A result which is not easily accorded with intuition.

According to Figure 6.8 above, the introduction of Insrop LNG supply will inflict a loss upon the Russian gas sales business. Not only will the contribution from pipeline exports decrease significantly, but also the combined contribution from Insrop LNG and Russian pipeline exports ends below the base case level. The reason is that the sales volume expansion is not strong enough to counterbalance the price reduction and higher average unit cost in Russian gas deliveries. Compared to the base scenario (BASE25), a 10 BCM Insrop development in 2005 brings about a 6.2 per cent increase in aggregate Russian gas exports paired with a 1.7 per cent decrease in the economic contribution. A large Insrop solution (LARGE25) infers a 17 per cent volume increase, but a 2.4 per cent reduced contribution. Also the strategies considered above to raise Insrop supply to the 30 BCM capacity border (i.e. expanded Emden capacity or price taking in France) entails a further economic deterioration.

According to this result it will *not* be in the interests of Russia to accept an Insrop LNG development. Even with a marginally positive contribution from Insrop, the logical decision from a simple economic point of view, should be no. This is because the model ignores some relevant considerations. It neither includes the alternative future value of the extra gas volumes sold, nor does it account for the possible negative effects on Russian gas prices due to increased shares in aggregate European gas consumption. As long as the purchasing countries focus on supply differentiation, their willingness to pay a premium for non-Russian gas is likely to increase with higher Russian market shares.

The supply situation is a primary key to the results attained here. An independent LNG development is not economically attractive if sufficient Russian gas volumes can be supplied through the pipeline systems at relatively moderate unit costs. This conclusion is not likely to be modified unless an emerging supply constraint in the current system cannot be solved without significantly increasing unit transportation cost. If that should happen, LNG may be reconsidered as an alternative to high cost investments in new petroleum provinces and/or long distance pipeline transport facilities (e.g. a Yamal development with pipeline exports). Due to the nature of project specific costs, the LNG alternative will be most competitive in the case of a fairly limited supply shortage or if gas demand estimates are regarded as highly uncertain. In the case of a more fundamental supply shortage - a situation that could result from a combined strong growth in Russian and European gas consumption - a full scale Yamal development may have to be considered within the horizon of this study. Pipeline transportation would thus most certainly be preferred, due to strong economies of scale.

In figure 6.9 average city gate gas prices for the 5 producer regions are calculated by dividing total incomes into aggregate gas sales for each of them. Another and perhaps more relevant price measure is shown in figure 6.10. Cif gas prices at four landing points are here given with reference to the most adjacent related market region. To calculate prices, the costs of re-gasification and downstream transportation are subtracted from estimated average city gate gas prices.

Figure 6.10 indicates significant variations in calculated gas prices at the various landing points. The highest prices are projected for deliveries to Belgium, while UK is at the bottom of the list. In base case estimates, Belgian gas price at landing point exceeds the UK price with about 30 per cent. For the LARGE25 scenario the price difference is around 23 per cent. The corresponding price differences referred to city gates are 22.6% (BASE25) and 17.6%

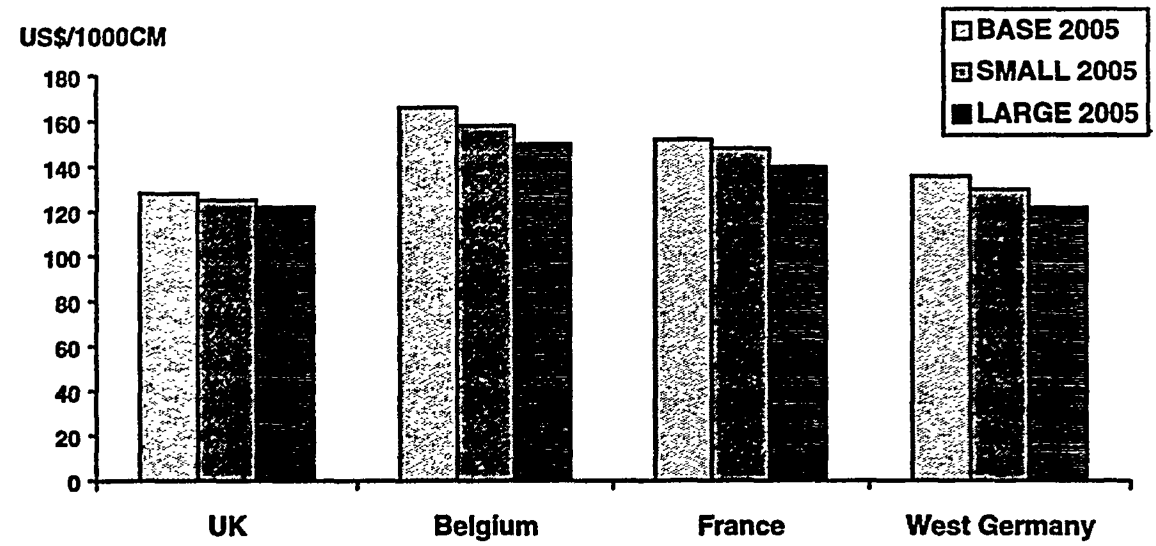

Figure 6.10 Net back Cif Prices at possible landing points for Insrop LNG.

(LARGE25) respectively. Net back calculations to well head[43] indicate possible base case prices at well head in the range from US$ 58 to US$ 98 per 1000 m^3.

Compared to the base case, the introduction of 10 BCM extra LNG in 2005 induces a 1.9 per cent reduction in average UK gas price at city gate. In Belgium and West Germany the corresponding price falls are 3.8 and 3.5 per cent, while average French gas price at city gate drops 2.5 per cent. At landing points the price decreases are estimated at 2.5 per cent in UK and 4.8, 4.7 and 3.1 per cent respectively in Belgium, West Germany and France. With the LARGE scenario (26.8 BCM gas) the corresponding city gate gas prices drop 3.8 per cent in UK and 8 per cent in the West German market.

A natural conclusion at this point is that the profitability of gas sales to North and Central Europe is vulnerable to new major supply expansions during the first decade of the next century. This conclusion is of course strongly related to the underlying assumptions on the development in European natural gas demand. Equally important are also the substantial increases in pipeline supply capacities outlined, particularly for Russia and Norway. It is highly probable that the pipeline projects assumed in this area will be realised. Construction works are already started on the new Russian export channel through Poland, and the European Commission has granted economic support to the project. In Norway several new pipelines are needed to fulfil already agreed gas sales contracts.

The profitability of future gas sales will also depend strongly on the development in other energy markets. Frameworks for gas will thus be influenced by balances and prices in oil and coal markets, as well as by political measures imposed by consumer countries. In this respect increasing environmental concern is a topic of particular importance, that has only attained fragmentary attention in this study. For instance, if governments decide to take effective actions against the problems of greenhouse gases, this will likely improve the position of natural gas, at least within the horizon of this study. The effects may work in much the same

[43] Cif landing point gas price estimates for BASE25 lie within in the range from US$ 128 to US$ 166.

way as an increase in prices of substitutes. To test for this, simulations were rerun with increased prices of fuel oils.

When prices of light and heavy fuel oils are increased to US$ 100 and 85 respectively (from US$ 85 and 65), the contribution from gas sales improves considerably. In 2005 the aggregate improvements for all 5 producer regions are estimated to lie in the range from 15 to 16 per cent. Relative improvements are approximately equal for the base case and the LARGE scenario. The effect is significantly stronger for UK production than for other producers[42]. With regard to Russia, the general increase in gas sales revenue does not alter the conclusion on Insrop LNG deliveries. Russian pipeline exports will still be more profitable on a stand alone basis than a combined pipeline and LNG solution.

6.3.3 Some closing remarks.

The simulations carried out above have concentrated on possible Insrop gas deliveries to the North and Western parts of Europe. These are the areas that shipments of North Russian LNG may be reached at the lowest costs. It is here, if anywhere, that Russian LNG will be capable of facing Algerian competition. Further south, Algerian cost advantages in transportation become increasingly predominant.

A possible paradox in this respect is that the purchasers' interest in supply differentiation is best served if Insrop delivers to the south and western parts of Europe (i.e. Spain and Portugal) while Algeria expands in the north. This is the solution that would contribute least to increases in Russian market power in countries where Russia is already very dominant. In West and East Germany for instance, the base case scenario predicts Russian market shares in 2005, at 47.2 and 49.6 per cent respectively. An additional 26.8 BCM Insrop supply to Europe, would raise Russian market shares in the two German regions to 52.7 and 59.2 per cent of total gas consumption. Under the large Insrop scenario, Russian market share will approach 50 per cent also in France. This may become a significant disadvantage for Russian LNG deliveries to these areas, and thus the realism in the assumption of a captive Insrop terminal in Germany may be strongly questioned. On the other hand, South European countries, like Spain, Portugal and perhaps Italy, could be willing to pay Insrop gas a price premium in order to reduce the current dependence on Algerian imports.

Two topics of particular importance for the simulations are the restrictions set for the development in British and Dutch gas production. In Holland it is presumed that a prudent exploration policy is maintained, leading to a stabilisation of annual production around 85 BCM. This is far below potential production capacity. For UK the practical capacity limit for production is assumed to lie somewhere between 85 and 90 BCM. This is at least 20 BCM below the potential capacity for UK indicated in Wood MacKenzie (April 1995). Should one or both of these assumptions turn out wrong, the market balance and gas prices in North and Central Europe will be influenced.

To test for the effect, UK production capacity was raised within the framework of the LARGE25 model scenario. UK was also allowed to act as price taker in Continental gas markets[44]. In this case UK annual gas production expanded to 106 BCM (compared to 88 BCM). Domestic consumption took 43 per cent of the expansion and reaches a total of 116 BCM. The remaining 10 BCM of the production increase was floated out through the Interconnector to Belgium. UK gas price at city gate dropped 7 per cent, to US $ 152 per 1000 cubic meters. Corresponding Belgian price level fell 12.5 per cent, to US$ 166. Net back CIF prices per 1000 cubic meters were thus brought down at US$ 112 in UK and US$ 126 in Belgium at the respective LNG landing points.

The UK production increase induces a 13.5 per cent reduction in the contribution to an Insrop LNG project compared to the outcome of the original LARGE25 scenario. The effect on the contribution to Russia from total gas sales is a 5.1 per cent decrease as compared to a 4.7 per cent decrease with no Insrop LNG included. These results support the logical conclusion that Insrop LNG is substantially more vulnerable than other Russian gas production, to what happens in UK and Holland.

Market structure and contract relations are put to the fore in the Wood Mackenzie (April 1995) study on the Interconnector. In our model simulations existing contracts and established company relations are ignored. Instead, all the suppliers are assumed to compete on equal terms, except for possible variations in the market behaviour of the suppliers themselves. Simulations will thus tend to underestimate the problems and costs of introducing a new supplier into the system. Compared to possible gas exports from UK, an Insrop supplier would certainly have fewer problems to reassure customers of the resource base for future deliveries. On the other hand, also Insrop LNG will face established contracts and trade relations. In this respect, not only other producers, but also companies engaged in downstream transport and distribution may see their interests challenged by new entrants into the gas business. These companies may thus use their influence, that is normally strong at the domestic level, to delay the development towards a freer gas market, which still seems likely to prevail in the long run. However, within the horizon of this study, the current market structure may still represent a significant obstacle to the development of an Insrop LNG project.

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[44] This last assumption is due to the likely problems of arranging long term sales agreements for British gas exports.

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8. REPORT REVIEW.

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27 Dec 1995

Elin Dragland
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1324 Lysaker, Norway

Review of INSROP Discussion Paper "European Gas Markets and Siberian LNG"

Dear Elin Dragland,

I experience difficulties in undertaking the review task. First, I am unclear about the readership of the paper. And second, I am unclear about the precise purpose of the review.

In the following comments, I assign to myself the role of referee for a professional journal like *Energy Journal* or *Energy Policy*, whose readership has a reasonable grasp of what goes on in the European gas market, and of economics.

These being my starting points, I recommend that substantial additional work is needed to make the paper fit for publication.

The first part of the paper (chapters 2 and 3) provide a general background the the European gas market into which the new LNG supplies might be inserted. In my view, this material is superficial and tedious reading for anybody reasonably acquainted with the European gas market.

Even if the readership consists of novices on the subject, I experience problems with the way the material is structured. As an introduction to potential new developments in ten years' time, the material should start out with a historical review, and not put it towards the end. Repeated references to the state of the market in 1994 are not very relevant, when the vista is stretched over several decades. After reading the text, I feel unclear about the direction the author believes the gas market is heading, and the ensuing implications. It is indeed relevant and important to regard the European market in the context of the North American and Pacific markets, but in my view, the author fails to explain the causes to the differences and their consequences for how the respective markets function.

The second part of the paper (chapters 4 and 5) introduces the economics of LNG and presents results of model simulations in which LNG from Siberia is introduced into Europe.

My main problem here is that I don't understand what goes on in terms of economics in the model simulations. To understand what will happen to future supply in a general equilibrium (least cost?) solution, I would need to know something about the levels and shapes of the cost curves of alternative suppliers to Europe. The only cost data, provided on p 55, suggest that Siberian LNG is more expensive than Algerian, and both appear to be substantially above the costs and prices of current piped supply. How, then, can the model churn out substantial supply of LNG from Siberia to Europe?

There are other implicit but important issues in the model which should be made explicit, to make the exercise understandable to the reader. For instance, what are the precise assumptions about market power and behavior of producers? Or, how does the model treat the different security of supply characteristics of LNG?

Furthermore:

The paper needs language editing.

Statement on p 1 about Russian LNG supply starting already by the turn of century is surprising.

I was greatly irritated by the author's use of three alternative ways for expressing costs and prices, without any attempt to provide conversion rates.

What is "OECD/IEA, Quarterly Journal of Energy" (p 51)?

Important references are missing. A particularly relevant opus is Dahl-Gjelsvik, *Resources Policy* Vol 19 No 3, Sept 1993.

A full list of references at the end of paper is essential.

Thank you for inviting me to review the paper. It has taken a good bit of time. Please be prepared to provide payment, if you plan to ask me again.

Sincerely,

Marian Radetzki

Please note that due to large changes to the original report the page references as found in this review no longer apply.

9. AUTHOR'S COMMENTS TO THE REVIEW.

I deeply regret the obvious confusion encountered regarding the purpose of the report and the compensation to the reviewer. Hence, I wish to inform that all issues in relation to the reviewing process have been handled by the INSROP Secretariat at the Fridtjof Nansen Institute. There has been no contact between the reviewer and the author of this report.

Readership.
The report is not intended for publication in a specialised, professional journal like *Energy Journal* or *Energy Policy*. It addresses a wider and less well-defined circle of readers and therefore it cannot be assumed that all readers are acquainted with the state of the European gas market. The general background information is thus intended both as a general service to the reader and more specifically as an outline for the assumptions used in the model simulations.

Organisation and content of background information.
The reviewer suggests that the historic review is moved to the front of the report. This is obviously a good idea and the material has been restructured to comply with this proposal. I find it more difficult to agree with the criticism regarding the references to the state of the market in 1994. Being the year that offers the most recent available data, it represents our point of departure for the journey into the future and thus is a year of specific interest.

The reviewer disagrees with the presentation of the links to non-European markets. Unfortunately his level of precision at this point is not such that the criticism may be of much help.

Model simulations.
In order to facilitate the understanding of the model economics, the presentation of the model and the specification of the scenario assumptions is improved. This includes a better description of the cost functions used in simulations. The extension also helps to answer the reviewer's question regarding the modelled diversification of supply: As producers are assumed to execute Nash-Cournot market power in most market regions, the general equilibrium solution may deviate substantially from a least cost solution (i.e. free competition).

The model treats LNG and piped gas in the same manner and makes no distinctions according to possible variations in the security of supply characteristics. In my view this approach is acceptable because the principal difference between the two means of transportation in this respect relates to the investment decision. That is a decision which is exogenous to the model.

Other issues.
It is certainly not the intention with this report to <u>state</u> that Russia will start to supply LNG by the turn of the century. The approach is clearly hypothetical, and the study only investigates the possible consequences <u>if</u> Russia should start such deliveries. The horizon for the scenarios was set in accordance with wishes presented by the project employer.

To avoid confusion about selected conversion factors, all cost estimates referred to other sources are expressed in the notation they appeared. Most figures are in addition supplied with converted values, either in the text or in footnotes. Hence, I am surprised of the reviewer's strong criticism at this point, which in my view is fairly unjust. Even though the conversion factors are not explicitly stated in the text, they can easily be deducted from the figures presented.

I gratefully acknowledge the information about the Dahl-Gjelsvik reference, which is now included in the text. Furthermore, I have also complied with the reviewer's proposal to move the references from footnotes to an appendix.