*In a natural gas market that is growing because of the increased use of gas in the generation of electricity, the organization and regulation of the industry is changing. This paper is concerned with the likelihood and desirability of 'deregulation' of the European gas industry. It is argued that prospects for further growth in the use of natural gas are promising, but that this depends, especially in Europe, on a continuation of state influence.*

*Avec un marché du gaz naturel en croissance en raison de l'utilisation accrue du gaz dans la production d'électricité, l'organisation et la réglementation de l'industrie évoluent. Ce document traite de la vraisemblance et de la désirabilité d'une "déréglementation" dans l'industrie du gaz en Europe. On y argumente que les perspectives de continuité de la croissance dans l'utilisation du gaz naturel sont prometteuses mais que celles-ci dépendent, particulièrement en Europe, du maintien de l'influence de l'État.*

# Limits of Deregulation in the Natural Gas Industry: the European Case

JACQUES PERCEBOIS

Natural gas is now considered as the source of energy that could most appropriately take on a larger role in the overall energy balance. This is in particular due to technical progress that has made gas one of the most competitive energy sources for electricity production. It is also due to an increase in concern for the environment, which awards a premium to gas as a clean energy. Lastly, it is due to the fact that, in a world of profound uncertainty, generating plants using natural gas can often be built more quickly than alternative types of plant (this holds true in particular when combined-cycle power plants are compared to large coal-fired or hydroelectric plants).

But the development of gas fields and the high cost of transporting gas and distributing it to final users require very large amounts of funds, which explains why gas is sold in markets that tend to be regulated. In general, natural gas is sold within the framework of long-term contracts by companies that are often totally or partially state-owned. Should we expect a 'deregulation' of this sector, and is it desirable?

I do not think so. As natural gas does not have a totally captive market, it must remain competitive with substitutes (oil and, increasingly, coal). Indeed, prospects for natural gas (which are discussed in part I of this paper) are promising, but on the assumption that the particular organization of the industry (relatively regulated with a powerful state influence) is maintained in the future. This is especially true in Europe (this argument is dis-

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cussed in part II).

## I. Promising Prospects for Natural Gas

World reserves of natural gas are estimated at 397 812 billion cubic meters, of which 143 444 $m^3$ are proven reserves. Based on total reserves, these would last for 195 years, or for 70 years on the basis of proven reserves — distinctly longer than the corresponding 45 years for oil. The expected life of these reserves has increased substantially in recent years due to technical progress that has enabled an improvement in the average recovery factor. Eastern Europe (mainly Russia) has 38% of proven reserves, 31% are in the Middle East, and the share of all other regions is less than 10 % (see Table 1).

The amount of gas supplied annually worldwide should increase sharply and stand between 2436 and 2848 billion cubic meters (bcm) per year by the year 2000, as against 2040 bcm in 1992. According to the World Gas Congress held in June 1994 in Milan, by the year 2020 the annual world gas supply should be between 2811 and 3450 bcm. As shown in Table 1, the potential gas supply is expected to increase everywhere but in Western Europe, where it will start declining after the year 2000.

The world demand for natural gas is projected to reach 2626 bcm in the year 2000, 3101 bcm by 2010, and 3401 bcm by 2020, as against 2045 bcm in 1992. This amounts to a 66% increase over less than 30 years. This basic scenario assumes that the annual rate of growth of gross domestic product will not be less than 2% within the OECD countries (the rise in gas demand would then be almost 80% in Western Europe over that period, as against 40% in North America, but almost 200% in Asia).

We also assume that the price of oil will rise moderately (from $15 to $25 (1992 US$) in 2000, $30 in 2010 and $35 in 2020). A strong increase in the market penetration of gas is expected, in particular as a fuel for electricity generation. This is due to the characteristics of electric power plants that use the combined gas-steam cycle: its efficiency (more than 50%, as opposed to 33% for a classical gas turbine and 38% for a coal-fired power plant); a relatively low unit-investment cost; a short building period; and environmental advantages compared to coal-fired power plants. The share of natural gas attributed to electricity production should then shift from 27% of total gas consumption in 1992 (for the whole world) to 34% in 2020 (Table 3). For instance, in Western Europe 6.3 % of electricity production came from gas in 1993 (see Table 5); this could increase to 16.8% as early as the year 2000 and be more than 30% by 2010.

This evolution is not the same everywhere. Gas penetration will be fastest within OECD and mainly in the newly industrialized countries of South-East Asia. The share of gas in the primary energy balance varies a lot among countries. It is very low in most developing countries. It reaches 10% in Japan, 19% in the European Community, 25% in the United States, and 43% in Russia. This variation is due to the fact that gas is a special fuel that must benefit from several favourable factors in order to be used. The transport and distribution of gas are expensive. It therefore requires a minimum level of users.

It is undoubtedly in electricity production that natural gas has the most promising prospects in developing countries. This is particularly true, at least potentially, in North Africa, Latin America and the Far East. In these countries, the industrial and domestic sectors, particularly the latter, do not have the same potential for gas penetration as Europe (Western as well as Eastern Europe) or North America.

In 1992, about 15% of world gas consumption involved international transactions (which is far less than the corresponding figure for oil). Given present and foreseeable energy prices, transport costs will act as a brake on the growth of international gas trade.

There are three large areas between which gas trade is very limited:

1) Western Europe, which has some of its own supply and gets additional supplies from North Africa and Russia;
2) North America, which is more or less self-sufficient; and

**Table 1:** World natural gas reserves (1/1/93)

| | Proved Reserves | | Additional Reserves | | Total | |
|---|---|---|---|---|---|---|
| | $10^9 m^3$ | % | $10^9 m^3$ | % | $10^9 m^3$ | % |
| Africa | 9 000 | 6 | 10 495 | 4 | 19 495 | 5 |
| East Europe (Russia included) | 55 800 | 38 | 103 250 | 41 | 159 050 | 40 |
| Middle East | 44 809 | 31 | 29 434 | 12 | 74 243 | 19 |
| North America | 9 430 | 7 | 53 650 | 21 | 63 080 | 16 |
| Latin America | 5 570 | 4 | 6 759 | 3 | 12 329 | 3 |
| West Eurpoe | 6 490 | 5 | 5 580 | 2 | 12 070 | 3 |
| West-Pacific and Asia | 12 345 | 9 | 45 200 | 17 | 57 545 | 14 |
| | 143 444 | 100 | 254 368 | 100 | 397 812 | 100 |

Source: UIIG (1994)

3) Asia – almost all of Japan's imports come from South-East Asia (Indonesia, Malaysia, Brunei), the Middle East and Alaska.

In the future, interrelations among these three areas are likely to expand, but the special characteristics of each of the three markets should still persist for some time. Table 2 clearly shows that in the basic scenario (the so-called optimistic scenario), the world gas supply should be large enough to meet demand until the year 2000. Indeed there will always be three distinct importing areas (Western Europe, followed far behind by Asia and North America). Current supply contracts that will be in force until 2000 or 2010 could be extended or even scaled up.

Imbalances will occur only on the assumption of a pessimistic scenario concerning gas supply (e.g., difficulties in finding the necessary funds to produce and transport gas from new gas fields). Then a rise in the price of gas on the world market should be expected, but it would be unlikely to provoke any 'gas shock,' as a large proportion of gas would then be replaced by abundant and cheap coal, especially in electric power plants. Rather than living with expected increases in the price of gas, the electricity sector would adapt its equipment plans to shift to coal if it has doubts about the security of gas supply. The relaunching of nuclear programs could also limit the progress of gas, but this prospect is at present unlikely.

The problem does not lie in the physical availability of gas resources: they do exist. The problem is to mobilize the resources so that they will be marketed when they are needed and at competitive prices. It is therefore a financial problem. At the present relatively low price (US\$3.5/$10^6$ Btu), gas is competitive with coal and will remain so if its price does not rise too much. But a portion of that price, which is also a ceiling, must be used to make the building of pipelines and liquefaction plants profitable, which leaves a rather modest rent to the producer. This makes expansion in Russia particularly uncertain. And Europe positively needs the Russian gas, and will need it particularly after 2010. The doubling of the Trans-Mediterranean pipeline from Algeria to Italy is being completed. The implementation stage of the pipeline linking Algeria to Spain via the Strait of Gibraltar has now started. Such uncertainties concerning the building of new pipelines can be alleviated if guarantees are obtained both from gas producers and buyers, which implies a particular institutional organization within the framework of long-run supply contracts. This is above all true in Europe and in Asia; it is less so in North America.

Some sources (e.g., Hafner, 1994) show that the price of gas could rise to US\$4, or even \$5, per $10^6$ Btu with gas remaining competitive with its direct substitutes, coal and fuel oil, in thermal power stations. This assumes that coal is priced at US\$50/ton and fuel oil at \$100/ton. The costs of pipeline transport (between 5000 and 6000 km) are as-

**Table 2 :** Supply/demand forecasts for natural gas for the year 2020

| | Potential supply $10^9 m^3$ | | | | | Forecasted demand $10^9 m^3$ | | | | Gas supply/demand | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Actual | Potential | | | | Actual | Forecasts | | | | | | |
| | 1992 | 2000 | | 2020 | | 1992 | 2000 | 2010 | 2020 | 2000 | | 2020 | |
| | | (1) | (2) | (1) | (2) | | (3) | (4) | (5) | (1)-(3) | (2)-(3) | (1)-(5) | (2)-(5) |
| Africa | 74 | 152 | 140 | 227 | 170 | 38.22 | 62.79 | 95.55 | 120.12 | 89.21 | 77.21 | 106.88 | 49.88 |
| East Europe (incl. Russia) | 757 | 1058 | 863 | 1210 | 1045 | 715.26 | 846.30 | 928.20 | 982.80 | 211.70 | 16.70 | 227.20 | 62.20 |
| Middle East | 117 | 193 | 166 | 267 | 237 | 106.47 | 147.42 | 180.18 | 199.29 | 45.58 | 18.58 | 67.71 | 37.71 |
| North America | 646 | 771 | 660 | 885 | 680 | 682.50 | 764.40 | 879.06 | 955.50 | 6.60 | -104.40 | -70.50 | -275.50 |
| Latin America | 69 | 117 | 90 | 173 | 145 | 60.06 | 87.36 | 122.85 | 152.88 | 29.64 | 2.64 | 20.12 | -7.88 |
| West Europe | 196 | 279 | 259 | 206 | 165 | 273.00 | 390.39 | 453.18 | 488.67 | -111.39 | -131.39 | -282.67 | -323.67 |
| West Pacific and Asia | 184 | 278 | 258 | 482 | 369 | 169.26 | 327.60 | 442.26 | 502.32 | -49.60 | -69.60 | -20.32 | -133.32 |
| Total | 2043 | 2848 | 2436 | 3450 | 2811 | 2045 | 2626.26 | 3101.28 | 3401.58 | 221.74 | -190.26 | 48.42 | -590.58 |

Source: UIIG (1994)
(1) = optimistic scenario
(2) = pessimistic scenario

sumed to be between \$2 and \$2.5/$10^6$ Btu. The costs of LNG transport are set between \$2.5 and \$2.9/$10^6$ Btu. With the price of gas at \$1/$10^6$ Btu (at the exporting country's border, at the entry of the pipeline or the liquefaction line), divided equally into production cost and margin (rent) for the producing country, there is a large gas supply in Africa, the Middle East or Russia. But it is necessary to find the \$10 to \$15 billion to build the pipeline, and the \$6 to \$8 billion for the LNG line.

## II. Organization of the Gas Industry

The natural gas market may be a vulnerable market. The choice to use natural gas was first made in countries with gas resources with a ready and sufficient potential market, or in the bordering regions of these countries. If the gas market is to expand, a conjunction of several favourable factors will be necessary.

*1. A critical level of potential users*

The high cost of transporting and distributing gas requires a sufficient number of potential users, either in urban areas or in industrial areas. Gas is not suited to meeting needs that are limited in quantity and geographically scattered. In many advanced industrial countries, the prior existence of a large distribution network for manufactured gas (produced from coal) provided a favourable factor for the penetration of natural gas. This is the reason why, in most developing countries (Africa in particular), the main potential utilization for natural gas remains electricity generation.

*2. A relatively competitive final user price*

In fact natural gas suffers from a major handicap — it has no captive market. It may have multiple uses and efficiently compete with heavy fuel oil, home heating oil, coal or electricity, but it is nowhere indispensable. Hence its penetration will largely depend on the prevailing economic conditions, in other words on its relative price. This argument may, however, have to be adjusted in the future if we consider that, for environmental constraints,

**Table 3 :** Breakdown by sectoral uses (world natural gas consumption)

| | 1992 | | 2000 | | 2010 | | 2020 | |
|---|---|---|---|---|---|---|---|---|
| | $10^9m^3$ | % | $10^9m^3$ | % | $10^9m^3$ | % | $10^9m^3$ | % |
| Residential/Commercial | 518.70 | 25 | 638.82 | 24 | 717.99 | 23 | 783.51 | 23 |
| Industry | 799.89 | 39 | 1007.37 | 38 | 1111.11 | 36 | 1171.17 | 34 |
| Power Generation | 551.46 | 27 | 780.78 | 30 | 1015.56 | 33 | 1143.87 | 34 |
| Others | 174.72 | 9 | 199.29 | 8 | 256.62 | 8 | 303.03 | 9 |
| Total | 2044.77 | 100 | 2626.26 | 100 | 3101.28 | 100 | 3401.58 | 100 |

**Source: UIIG (1994)**

natural gas will be greatly appreciated for electricity generation. But, even in this case, it will not be a 'captive market' due to competition from coal.

*3. A selling price profitable enough to justify expenditures made all along the gas chain*

The low price of energy for a long time compromised the development of international gas trade. The rise in energy prices after 1973 made the development of such trade profitable. This is the reason why most of the natural gas produced (gross production minus flared or reinjected gas) is today marketed within the producing countries (85%). The main natural gas importers are, and until 2000 or even 2010, will be OECD and Eastern European countries; i.e., industrial countries which alone have and will have a sufficient transport and distribution network. Western Europe, the US and Japan still are the main potential buyers of internationally marketed natural gas. Of course, as already mentioned, a potential market for electricity generation exists in several developing countries with gas reserves or that are located near producing countries, though this market is narrow (North Africa, Eastern Asia, etc.).

CONTRACTS AND PRICING

Thus the narrowness of the market explains how the leeway that consumers have to find suppliers and that producers have to find customers is much less than in the case of oil. This narrowness, its partition into three areas (America, Europe, Asia), and the great barriers to entry (in the form of distribution and transmission costs) largely explain differences that can be noted in the terms of the various contracts. The bilateral nature of the relations between gas exporters and importers leads to long-term supply contracts (20 to 25 years) and explains why gas pricing generally is based on negotiated compromises rather than spot prices.

Markets are, in fact, separated and conditions in them are negotiated on the basis of the bargaining power prevailing when the contracts are drawn up. As people from Gaz de France have said: "An import contract is equivalent to a marriage settled 10 years in advance for a term of 20 years."

It is possible, however, to observe a relative harmonization of contract terms.

The sharing of gas rent (the difference between the gas price to the final user and the total cost of production, liquefaction, transmission, storage and distribution) is the main point of negotiation between sellers and buyers. Two uneasily consistent pricing methods are in opposition in the international natural gas market: the *parity method,* supported by at least some of the exporters and the *'net-back' method,* supported by importers.

For exporting countries a 'fair' pricing of natural gas must be based on the parity of gas and oil FOB prices. This argument was developed in particular when oil prices were high (at the beginning of 1980s). The gas exporting country must be able to charge a selling price equivalent, at the port of embarkation, to the price it already charges for its oil, a price covering not only the technical costs of production but also the opportunity cost due to the non-renewable nature of the gas resource. In other words, too low and hence insufficiently

**Table 4:** Cost of power generation (gas and coal)

| Type of Power Station | Fuel | Efficiency (%) NCV[1] | | | Investment cost (1990 US $ /kW) | | |
|---|---|---|---|---|---|---|---|
| | | 1990-2000 | 2000-2010 | 2010-2020 | 1990-2000 | 2000-2010 | 2010-2020 |
| Gas turbine | natural gas | 33 | 36 | 38 | 290 | 280 | 265 |
| Combined cycle | natural gas | 51 | 53 | 56 | 470 | 460 | 445 |
| Traditional coal | coal | 38 | 38 | 38 | 1000-1250 | 1000-1250 | 1000-1250 |

1/ net calorific value

Source: SESEE (1991) quoted in Hafner (1994)

profitable FOB prices will prevent known reserves from being exploited and consumers will be the first to bear the expenses resulting from this.

To this sort of argument favouring an upstream-to-downstream system, the importer opposes an argument in favour of a downstream-to-upstream process — a net-back formula. Natural gas is not a substitute for crude oil but is rather a substitute for certain oil products (heavy oil or home heating oil) or for coal, or even electricity. Unduly high prices for gas will therefore destroy the market by preventing potential substitutions.

As gas has no captive uses, it must either defend a threatened market share or painfully conquer new outlets. It must therefore remain competitive with all fuel oils, in particular heavy oils, the value of which is much lower than that of crude oil. Gas must be able to durably compete with the less costly forms of energy for which it wants to be substituted. This is all the more true as, to develop, the gas market must include the industrial and power generation sectors. In Europe, as in the US, industry represents a large potential market. (About 39% of the gas consumed is now used in industry. Soon this proportion will be only 34-36%, but the role of electricity generation will consequently be increased.)

Industry and even power generation represent a relatively stable demand for natural gas, as opposed to domestic uses, which are subject to peak phenomena. This is less true in the case of power generation when gas is used for peak period production. In fact, we may consider that natural gas will be largely used in the future to produce electricity during off-peak periods, in competition with coal.

Thus, according to the net-back approach, it is necessary to start from the average price of the substitutes for gas from the viewpoint of final users and, going back up the gas chain, to deduct the costs of distribution, storage, eventual regasification, and international transmission, to obtain the 'optimal' or at least maximum level of the FOB price that can be paid to the exporter.

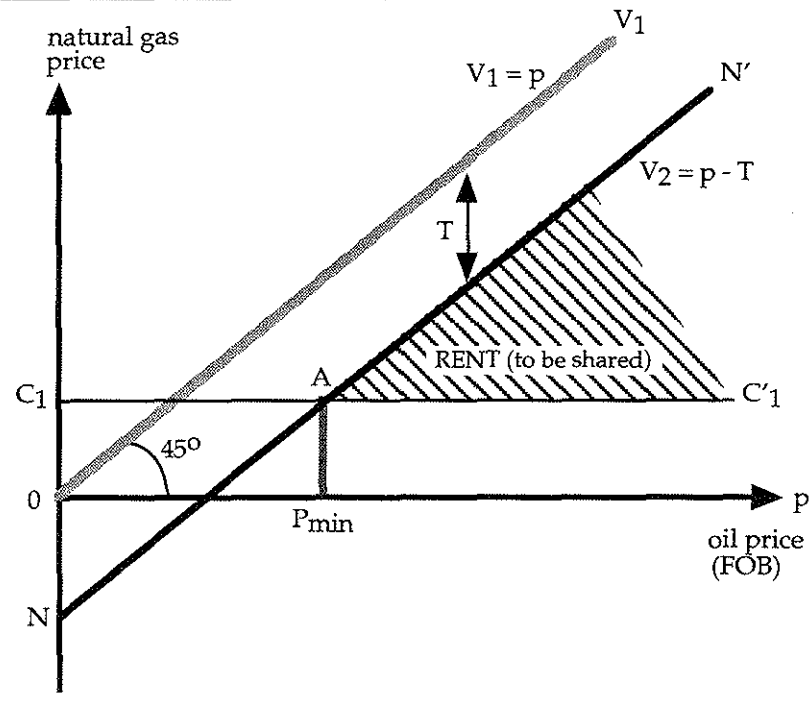
The net-back approach allows one to propose some simple pricing principles, which are illustrated in Figure 1.

*Rule 1:* The average selling price of natural gas for the final user cannot (in Europe in particular) exceed the international energy-equivalent price of crude oil (if gas is used in all of the industrial, domestic and power generation sectors) or the international price of coal (plus the cost of coal transportation) if gas is used only to produce electricity.

*Rule 2:* The purchase price of natural gas at the border of the importing country (the CIF price) cannot exceed, again in Europe, a percentage $x_1$ of the international price of crude oil, where $0 < x_1 < 1$ and $(1 - x_1)$ is the per-unit cost (distribution and storage) of delivering the gas within the importing country.

*Rule 3:* The purchase price of natural gas at the border of the supplier's country (the FOB price) cannot exceed a percentage $x_2$, where $0 < x_2 < x_1$, of the international price of the reference crude oil. That is, $(1 - x_2)$ is the per-unit cost of delivering the gas from the exporter's border to the final user.

Figure 1 can be used to indicate the rent available to be shared in relation to different levels of the international price of oil. $OV_1$, a




$V_1$ = natural gas value at the user level

$V_2$ = net-back value for natural gas at the exporter border (FOB price)

T = cost of transmission and distribution of natural gas

$C_1$ = natural gas cost at the exporter border (FOB price)

**Figure 1:** Natural gas rent sharing

Source: Percebois (1989b)

45°-line, shows the maximum price of natural gas in Europe for each possible oil price, assuming that European gas users are prepared on average to pay only up to the equivalent oil price, taking into account the various uses of gas in the domestic and industrial sectors.

Let $T = (1 - x_2)p$, the cost of transmitting, storing and distributing a unit of gas from the exporter's border to the final user. Then the net-back value of natural gas at the exporter border (FOB price) will be $V_2 = p - T$, with the line NN' representing all such values of $V_2$.

$C_1C_1'$ represents the cost to the producer of extracting the gas and delivering it to the border for export. The rent to be shared between the seller and the buyer is then the difference between $V_2$ and this cost. A positive rent will thus be available to share only if the price of oil is high enough to cover both sets of costs ($C_1$ and T), and this will occur only for $p > p_{min}$. Thus the possible rents to be shared are represented by the area $N'AC_1'$.

It is obvious that under net-back pricing the best prices available to the exporter are represented by the 'price path' $C_1AN'$. That is, when the price of oil (or coal if the main substitute is coal) is low, the exporter will sell gas at $C_1$; a net-back price at the loading port would be less than the production cost. When the price of oil rises above $p_{min}$, the exporter will want to sell gas at the net-back value, which would enable it to recover the whole of the available rent.

The best prices from vantage point of the importer of gas (who will have to cover the costs represented by T) are shown by the 'price

**Table 5 :** Structure of power generation in Western Europe (%)

| Source of energy | 1993 | 2000 |
|---|---|---|
| Nuclear | 23.1 | 21.3 |
| Hydro | 18.3 | 16.5 |
| Multi-fuels | 16.0 | 14.7 |
| Coal | 20.8 | 18.4 |
| Oil | 10.7 | 7.5 |
| Natural gas | 6.3 | 16.8 |
| Others | 4.8 | 4.8 |
| | 100.0 | 100.0 |

Source: UNIPEDE

path' $NAC_1$'. The importer is willing to pay only the net-back FOB value when the price of oil is low and would prefer to pay only $C_1$ when the price of oil rises above $p_{min}$. In the latter case, the importer would be able to recover the whole of the rent included between the net-back value AN' and the production cost $AC_1$'.

Thus the goal of price negotiations is the sharing of the gas rents $C_1$'AN'. To defend the cost of production as logical, whatever the price of crude oil may be, amounts to giving guarantees to the producer. It is then justified for the importer, who takes risks (including the risk of buying gas at a price higher than its value), to profit from the gas rent when there is one. On the contrary, to defend the net-back value as logical whatever the price of crude oil may be, amounts to giving guarantees to the user. The exporter, who takes risks (including the risk of selling its gas at a price lower than its cost of production when the price of crude oil is low), is then justified in profiting from the gas rent when there is one.

In other words, the gas rent should be appropriated by the party who bears the risks implied by the choice of a given price formula.

Because of the considerable investments that have to be made both by the producer and by the importing company and distributors, it is absolutely essential, in order to put in place the infrastructure necessary for marketing the gas, to be able to guarantee that gas will be available in the very long term. In this environment, import contracts signed by producers and importing gas companies exhibit the following features:[1]

- they are long-term contracts (20-25 years);
- they contain constraints on both seller and buyer, in the form of obligations to supply and to take gas respectively; and,
- because risks are shared between the parties, rents are also shared.

Technical production risks and the risk of price fluctuation are borne by the producer/supplier (through an index formula linking the gas price and oil price). The volume risks connected with the sales of the gas in the market are borne by the buyer/importer via 'take-or-pay' clauses contained in the contract.

### REGULATORY CHANGES?

The above discussion of risk-sharing and pricing suggests why a large number of gas companies are publicly-owned firms, or mixed firms. This is the case in Europe, and partially the case in Asia (see Table 6). One also observes that the role played by governments is important in the exporting countries as well as in the importing countries. This form of government regulation is a condition for the stability and the development of the gas market in Europe. At the same time, while political and macroeconomic constraints (in particular concerning financial and industrial compensations) are never totally absent from gas negotiations, the logic of market-oriented pricing is now a greater determining factor.

In several European countries, the importation, transport and distribution of gas produced or imported are legal monopolies or quasi-monopolies operated by public companies. This is often the case in the exporting countries. As an example, GAZPROM has monopoly rights over the production, transmission, distribution and export of Russian gas. Similar monopolies exist in Algeria, Indonesia, Abu-Dhabi and other countries.

Should we expect the abolition of these monopolies? Should we expect the adoption of

1/ This applies to Europe and Asia. Contracts in North America are somewhat different.

**Table 6 :** The main actors on the international gas market

| Importer countries | Main firms | Private or Public? | Volume[1] |
|---|---|---|---|
| Austria | OMV | Mixed (state 70 %) | 5.2 |
| | Austria Ferngas | Mixed | |
| Belgium | Distrigaz | Mixed (state 50 %) | 8.7 |
| Finland | Neste Ov | State (97.7 %) | 2.8 |
| France | GDF | State (100 %) | 26.2 |
| Germany | Ruhrgas | Private | 44.4 |
| | BEB | Private | |
| | Thyssengas | Private | |
| | Wintershall | | |
| Italy | SNAM (ENI) | State (100 %) | 27.5 |
| Japan | Mitsubishi | Private | 44.5 |
| | Nissho Iwai | Private | |
| | Mitsui, etc... | Private | |
| Spain | ENAGAS | State (100 %) | 5.4 |
| United Kingdom | British gas | Private | 5.6 |
| United States | Distrigas | Private | 40.7 |
| | Panhandle | Private | |
| | El Paso | Private | |
| **Exporter Countries** | **Main firms** | **Private or Public ?** | **Volume[1]** |
| Abu-Dhabi | ADNOC | State (100 %) | 3.4 |
| Algeria | SONATRACH | State (100 %) | 32.3 |
| Canada | Transcanada | Private | 38.8 |
| | Alberta Natural Gas Co | Private | |
| | etc... | | |
| Indonesia | Pertamina | State (100 %) | 26.5 |
| Netherlands | Gasunie | Mixed (state 50 %) | 29.0 |
| Norway | Statoil | State (100 %) | 22.0 |
| Russia (Cei) | Gazprom | State (100 %) | 74.3 |

1/ 1991 figures in $10^6$ l.o.c.

a 'common carrier' system (Third-Party Access) for natural gas, as proposed by the European Commission? Some arguments may be advanced against the common carrier system.

*1) The adoption of a Third Party Access system would jeopardize the logic of long run supply contracts.*

As they will no longer have reliable outlets, gas companies will no longer be able to enter into long-run contracts. Thus there could be a reduced supply reliability on the one hand and a risk of shortages on the other. This reluctance to enter into long-run contracts will tend to 'freeze' the development of any new production project. Again the comments of some analysts at Gaz de France are relevant.

> Our job is to sell to customers, who are not obliged to buy, the natural gas we buy from suppliers who are not obliged to sell to us. Why then should we be obliged to transport natural gas for customers who could buy it from us, and for suppliers who could sell it to us, but who together have decided to negotiate directly without us?

*2)The adoption of a common carrier system will increase the number of gas buyers and will result in a weakening of the positions of buyers in relation to gas sellers.*

At present cooperation among European gas companies leads to a harmonization of contractual conditions in Europe and attractive purchase prices. The common carrier system will put an end to this cooperation by bringing in unnecessary competition. Producers will sell more and make more profits, but these will be risky gains. This will additionally make gas prices on the European market more unstable.

Import monopolies and transport monopolies are not omnipresent in Europe. It is possible to abolish such monopolies, to achieve transparency in regard to gas purchasing and selling conditions, and to implement a system of 'free transit for gas' without accepting a Third Party Access system. ('Free transit' would involve open access for foreign companies that buy gas abroad. It is a form of common carriage reserved for gas transportation companies. For some observers this would be the first step towards a generalized common carrier system. For others, on the contrary, it would be a substitute for a common carrier system that would be open to all users.)

For these reasons deregulation in the European gas market will be limited.

## III. Concluding Remarks

*1) The European natural gas market is a club made up of a few companies whose managers know one another very well because for many years they have either negotiated together or opposed one another.*

These buyers and sellers have managed to ensure security of supply globally with a network of connected pipes and to impose the net-back logic within long-run purchase contracts. The European gas market must be 'regulated' through stable relationships. This is also in the 'fair' interest of such sellers as Russia, Algeria, and possibly others.

A European energy policy is not easy in a context in which the UK is oil-oriented, the Netherlands gas-oriented, Germany coal-oriented, France nuclear-oriented and Italy dependent on its imports. But for European countries natural gas has tended to be an element of complementarity and cooperation, rather than an element of dissension. Why change a system that is in operation and works? Is the common carrier proposal merely a threat of the European Commission in order to obtain concessions in other fields (for instance, transparency of gas pricing, because gas contracts are still confidential)? Is it not but a means of reinforcing its power of regulation? This is why I think that 'deregulation' must be limited in this market.

*2) Three important changes have recently occurred in the power-generation industry.*

- Technical progress in gas turbines has made it possible to develop the highly energy-efficient combined-cycle technique on a large scale.
- Regulations for environmental protection have been made much more stringent. From this point of view, natural gas keeps advantages in comparison with coal.
- The moratorium concerning the construction of new nuclear power stations, along with forecasting risk in the power generation industry, have led electricity producers to prefer plants that can be constructed as rapidly as possible and to prefer smaller investments (i.e., combined cycle units). In fact, everywhere coal is the only alternative to gas for new power stations planned in the next few years. However, in this light power generators require the gas industry to guarantee that the total production cost per kWh in gas-fired units will be maintained at a level equal to those of coal-fired units throughout the entire life of the combined-cycle power station. This guarantee can be given only if the price of gas is indexed to that of coal.

One of the basic interests that the producer and the distributor have in common is without any doubt ensuring a continuous and long-term outlet for the quantity of gas for which

both have invested. This supposes a favourable environment that will encourage the gas industry to invest in exploration, production, transmission and distribution. This is the main reason why some minimum level of regulation is necessary in the gas industry.

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