ESMAP

Energy Sector Management Assistance Programme

The Future of Natural Gas in Eastern Europe

Report No. 149-92

A joint report with the

Europe & Central Asia and
Middle East & North Africa Regional Offices

JOINT UNDP / WORLD BANK
ENERGY SECTOR MANAGEMENT ASSISTANCE PROGRAMME (ESMAP)

PURPOSE

The Joint UNDP/World Bank Energy Sector Management Assistance Programme (ESMAP) was launched in 1983 to complement the Energy Assessment Programme, established three years earlier. ESMAP's original purpose was to implement key recommendations of the Energy Assessment reports and ensure that proposed investments in the energy sector represented the most efficient use of scarce domestic and external resources. In 1990, an international Commission addressed ESMAP's role for the 1990s and, noting the vital role of adequate and affordable energy in economic growth, concluded that the Programme should intensify its efforts to assist developing countries to manage their energy sectors more effectively. The Commission also recommended that ESMAP concentrate on making long-term efforts in a smaller number of countries. The Commission's report was endorsed at ESMAP's November 1990 Annual Meeting and prompted an extensive reorganization and reorientation of the Programme. Today, ESMAP is conducting Energy Assessments, performing preinvestment and prefeasibility work, and providing institutional and policy advice in selected developing countries. Through these efforts, ESMAP aims to assist governments, donors, and potential investors in identifying, funding, and implementing economically and environmentally sound energy strategies.

GOVERNANCE AND OPERATIONS

ESMAP is governed by a Consultative Group (ESMAP CG), composed of representatives of the UNDP and World Bank, the governments and institutions providing financial support, and representatives of the recipients of ESMAP's assistance. The ESMAP CG is chaired by the World Bank's Vice President, Operations and Sector Policy, and advised by a Technical Advisory Group (TAG) of independent energy experts that reviews the Programme's strategic agenda, its work program, and other issues. The Manager of ESMAP, who reports to the World Bank's Vice President, Operations and Sector Policy, administers the Programme. The Manager is assisted by a Secretariat, headed by an Executive Secretary, which supports the ESMAP CG and the TAG and is responsible for relations with the donors and for securing funding for the Programme's activities. The Manager directs ESMAP's two Divisions: The Strategy and Programs Division advises on selection of countries for assistance, carries out Energy Assessments, prepares relevant programs of technical assistance, and supports the Secretariat on funding issues. The Operations Division is responsible for formulation of subsectoral strategies, preinvestment work, institutional studies, technical assistance, and training within the framework of ESMAP's country assistance programs.

FUNDING

ESMAP is a cooperative effort supported by the World Bank, UNDP and other United Nations agencies, the European Community, Organization of American States (OAS), Latin American Energy Organization (OLADE), and countries including Australia, Belgium, Canada, Denmark, Germany, Finland, France, Iceland, Ireland, Italy, Japan, the Netherlands, New Zealand, Norway, Portugal, Sweden, Switzerland, the United Kingdom, and the United States.

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ESMAP Operations Division

Foreword

This report was prepared for a seminar, "Natural Gas in Eastern Europe - Regional Issues and Options," hosted by the World Bank. The seminar, which was held in London on January 17-18, 1992, brought together key decision-makers, whose names appear as an appendix, from the gas-consuming countries in Eastern and Central Europe, major gas-producing countries and international organizations. The World Bank wishes to express its appreciation to the Overseas Development Administration of the UK for cosponsoring the seminar. The report is being published in its original form. The recent political changes that have taken place in the region and in the former Soviet Union have, therefore, not been reflected in the report.

This background report for the seminar was prepared by consultants Arthur D. Little and funded as a joint report by the Europe & Central Asia and Middle East & North Africa Regional Offices (Country Departments EC1, EC2, EC3, MN1, & EMT) and the ESMAP Operations Division. Bank staff who initiated and supported the completion of the report included Messrs/Mmes.: A. Mashayekhi (Division Chief), C. McPherson (Principal Energy Economist), Z. Alahdad (Principal Energy Specialist), P. Nore (Senior Energy Economist), M. Shirazi (Senior Gas Specialist), P. Law (Energy Specialist), H. Hahm (Economist), and B. Svensson (Energy Economist/Task Manager).

Large reserves of natural gas in some countries and growing import requirements for efficient and environmentally benign fuels in other countries create a potential for growth in natural gas trade within Eastern Europe and between this region and other regions. This activity is a part of the Bank's continuous efforts to encourage efficient and economic development and trade of natural gas in Europe, Central Asia, and the Middle East and North Africa.

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Summary

1. As part of the process of economic development, the countries of Eastern Europe need to consider how to structure their future energy supplies in order to satisfy the demands of a growing economy. In most of these countries, gas has so far played a relatively minor role, with coal being the dominant source of energy. Due to an urgent need to improve the environment, several of the countries are now considering an increase in their natural gas consumption. Eastern Europe is thus facing a significant aggregate gas demand increase and needs to negotiate contracts for incremental supplies. Historically, all imported gas came from the Soviet Union. However, there is now a wish to diversify away from this source, partly to reduce the risk of supply curtailment due to technical reasons.

Key Issues

2. In considering future gas supplies for Eastern Europe, the following key issues need to be addressed:

- The availability of costs of the supply options.
- Consumer pricing and its effect on the economic viability of the supply options.
- The merits of a regional versus an individual approach to gas import projects.
- The costs and benefits of supply diversification.
- The availability and mobilization of project investment funds.

3. Natural gas could potentially be imported from several other suppliers, such as Norway, North Africa, or the Middle East. Each supply area has its own characteristics, largely determined by geology and geography. Some offer the possibility of gas reserves which can be developed at low cost, others have higher cost reserves because of their distance from the European market, or because the gas fields are relatively small or offshore. Some suppliers are perceived as very reliable in both the technical and commercial aspects of a long term gas purchase agreement, others are perceived as less secure because of labor problems, technical difficulties or geopolitical conflict.

4. East European buyers are likely to face very strong competition for available gas volumes from West European gas companies, which have larger supply gaps to fill and are able to offer substantially higher prices. In order to access additional volumes, East European buyers will need to make realistic assessments of the size of their gas markets and the levels of gas prices which users can afford to pay. The degree of supply diversification, as well as the premium which can be paid for it, should be determined before the gas purchase negotiations begin.

5. In developing energy policies the governments of Eastern Europe are confronted by tasks which are very complex and may be too difficult and time-consuming to resolve. In forming their natural gas purchasing strategies, opportunities for cross-border cooperation should be exploited whenever possible. This may serve to reduce costs by increasing the opportunities to benefit from economies of scale and by increased negotiating power towards suppliers. The formation of one or more regional gas purchasing consortia may be desirable, and opportunities for cooperation with upstream partners may be desirable.

6. While the wish to achieve diversification of gas supplies is reasonable, it should be appreciated that gas from the Soviet Union is likely to continue to be the lowest cost supply available. The addition of new supply sources, while the bulk of supplies continue to be imported

from the Soviet Union, may, from an economic point of view, be better than a major shift in supplier preferences.

7. Increased security of supply may be achievable not only through diversification of supply, but also through construction of gas storage facilities. In addition to investment in new indigenous gas production and gas storage facilities where possible, it is essential that an appropriate gas pricing philosophy is adopted and that consumer prices accurately reflect the underlying economic costs associated with the provision of gas supply. A rational pricing policy is likely to be a necessary condition in order to attract investment from Western lenders, whether these are loans from commercial or non-commercial sources, or equity funds. Western investors will require that new projects can earn an appropriate rate of return in a wide variety of economic circumstances and thus ensure that the best investment decisions are made.

Demand

8. Three demand scenarios have been created for each country, of which the base case represents a "best estimate" given current plans and economic outlook, and the high and low cases indicate a reasonable range of uncertainly. In the base case scenario, it is envisaged that overall demand in Eastern Europe will decline initially but return to its 1990 level of 80 BCM by 1995. The decline in demand is expected to take place in the industrial sector due to a combination of factors such as closure of noncompetitive and/or environmentally hazardous industries, increased energy conservation and initial end-use efficiency improvements. The decline in the industrial sector will be somewhat offset by growing demand in the residential/commercial and power generation sectors. After 1995, demand will grow by 2.8 per cent per annum during the 1995-2000 period and by 3.6 per cent per annum during the 2000-2010 period.

9. Over the long term, the power generation and industrial sectors will account for the largest volume of gas demand growth, though the residential and commercial sectors will have the largest percentage increase in demand.

10. In the low scenario, economic stagnation up to 2000 is envisaged, followed by economic growth after 2000. This scenario also assumes little improvement in energy end-use efficiency and limited replacement of coal-fired capacity.

11. The high scenario, by contrast, assumes strong economic recovery from the mid 1990s and onwards, improvements in end-use efficiency and some replacement of coal-fired capacity by gas. No scenario assumes additional development of nuclear capacity.

East European Gas Demand Forecast (BCM)

	1990	1995	2000	2005	2010	Average Growth %
Low Scenario	80.7	79.0	86.4	97.3	109.5	1.5
Base Case	80.7	79.7	91.5	109.6	131.0	2.5
High Scenario	80.7	81.0	102.0	133.0	172.8	3.9

Committed Supply and the Supply Gap

12. Indigenous gas production seems likely to decline very rapidly after the mid 1990s, without additional discoveries. Current output of 37 BCM p.a. will decline to 10-15 BCM p.a. around 2000, unless the introduction of better technology and higher wellhead prices encourages further exploratory efforts which are successful.

13. The Soviet Union can be expected to extend its current contracts at levels similar to today, approximately 40 BCM p.a., and there are small volumes of imports contracted from Algeria and Iran. In total, Eastern Europe may face a potential deficit of 35 BCM by 2000, rising to more than 50 BCM by 2005, and over 70 BCM by 2010. Western Europe's potential deficit could be even greater, and calls into question the ability of the oil and gas industry to invest sufficient funds on a timely basis to enable demand to rise to the levels indicated. Failure to do so will result in scarce supplies and higher prices; Western European buyers are likely to outbid those of Eastern Europe for access to additional supplies. For the purposes of illustrating the deficit, a scenario of constrained demand in the second half of the 1990s has been used.

Projected European Gas Supply and Demand Balance (BCM)

	1990	1995	2000	2005	2010
Western Europe					
Demand (Low Case)	*260*	*296*	*309*	*329*	*350*[a]
Supply (Committed)					
Indigenous	121	127	125	100	75
Norway	28	27	35	35	35
Soviet Union	55	64	64	64	64
Algeria	28	38	40	40	40
Netherlands	28	40	40	40	40
Nigeria	0	0	5	5	5
Deficit	***0***	***0***	***0***	***45***	***91***
Eastern Europe:					
Demand (Base Case)	*81*	*80*	*92*	*110*	*131*
Supply (Committed)					
Indigenous	37	36	12	13	14
Soviet Union	44	38	40	40	40
Algeria	0	2	2	2	2
Iran	0	3	3	3	3
Deficit	***0***	***0***	***35***	***52***	***72***
TOTAL DEFICIT	**0**	**0**	**35**	**97**	**163**

a. High case demand would be 460 BCM by 2010, and the corresponding total deficit 273 BCM.

Supply Options: New Projects

14. There are many potential projects which could be developed to supply Eastern Europe, including:

- A new pipeline from West Siberia.
- A pipeline from Iran via Turkey.
- A pipeline from Norway to Poland via Germany or via the Baltic Sea.
- A new pipeline from Algeria via Italy.

- A new LNG terminal in the Baltic Sea to import gas from Norway.
- A new LNG terminal in the Adriatic to import gas from North Africa or the Middle East.

15. The costs of several new projects which could deliver incremental volume of gas to Eastern Europe have been assessed. Necessarily, the cost levels must be regarded as indicative only and are regarded as being accurate to within ± 30 per cent because they are not based on detailed pipeline route surveys, etc. Nevertheless, they give an indication of the likely economic viability of the projects, and the large amounts of capital required.

Supply Options to Eastern Europe

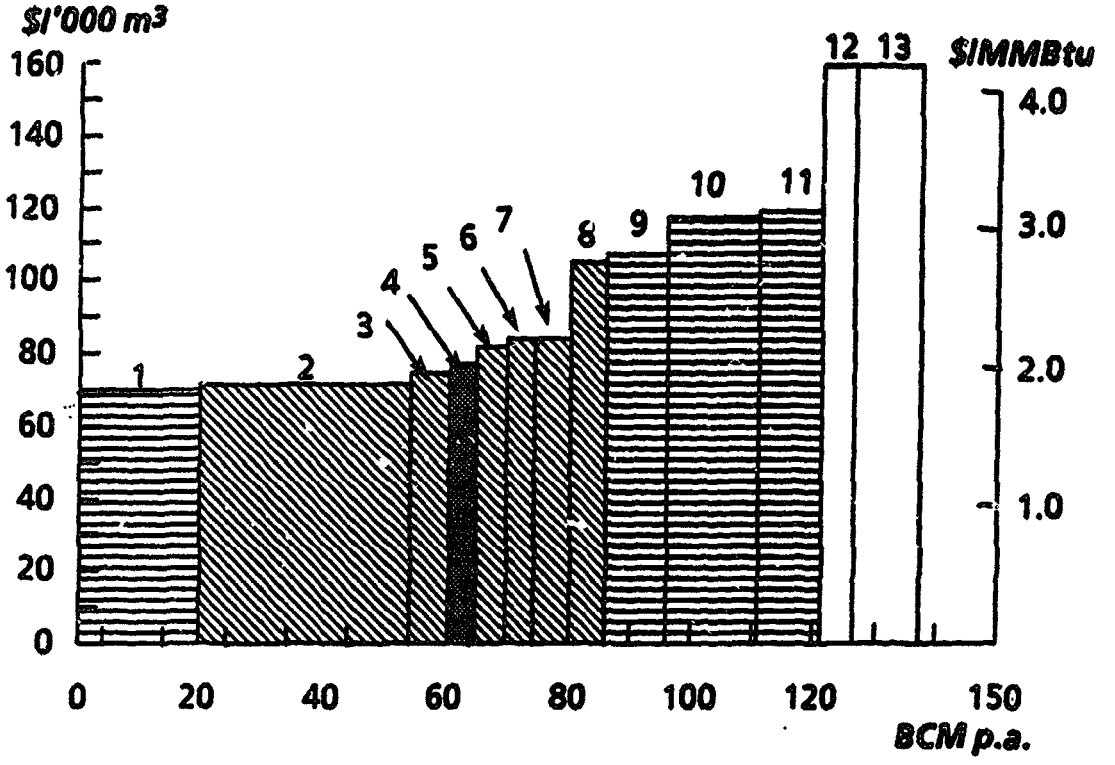
Source	Supply Options Up to 2000	Capital Investment Required[a] ($bn)	Annual Volume (BCM)
Soviet Union	Incremental West Siberian gas through existing network.	1	10
	Incremental West Siberian gas through new pipeline to Uzhgorod	14	35
Algeria	Pipeline gas through transmed to Monfalcone.	7	5
	LNG from new plant to proposed terminal in Yugoslavia	6	5.5
Libya	LNG to proposed terminal in Yugoslavia	6	5.5
Qatar	LNG to proposed terminal in Yugoslavia	7	5.5
Soviet Union	Barents Sea gas delivered via new pipeline to Polish border	6	11
Norway	North Sea gas via Emden and Midal/Stegal to Litnov.	6	10
	Tromsoflaket gas (Snohvit) as LNG to Gdansk.	6	5.5
Iran	New pipeline from Iran through Turkey to Bulgarian border	9	20

a. Includes investment required in transmission/distribution infrastructure (including Eastern Europe), incremental production facilities, liquefaction, regasification and shipping

16. Of all the supply options studies, incremental gas volumes form the Soviet Union delivered through the existing pipeline system would appear to represent the lowest cost option. At present, only 10-15 BCM of spare pipeline capacity is believed to be available. Beyond this new production capacity must be developed and additional pipelines built.

17. Of the non-Soviet supply options, Iranian gas would seem the least costly, but is not likely to be available before 2000. The cost of new Algerian pipeline gas or LNG is above $2/MMBtu, which is still considerably lower than the cost of Norwegian gas.

Supply Cost Curve for Eastern Europe



Supply Options

1 Iranian gas at Bulgarian border
2 USSR gas at Uzhgorod
3 USSR gas at Beregdaroc
4 Algerian gas at Monfalcone
5 USSR gas at Ismail
6 USSR gas at Brest-Litovsk
7 North African LNG at Omisalj
8 Qatar LNG at Omisalj
9 Norway Polpipe
10 USSR (Barents Sea to Brest-Litovsk)
11 Norway via Emden
12 Norway LNG at Gdansk
13 USSR Barents Sea LNG at Gdansk

Deliveries from:

1994
1996
2000
2005

18. When looking at potential new supply sources, serious consideration should be given to Algeria and Iran. Both have large gas reserves and substantial volumes which could be developed for sale to East European buyers at a cost which is close to current European border prices, Algeria in the short to medium term and Iran in the longer term. Norway, on the other hand, seems to be a less attractive potential supply source because of the high cost of developing gas fields offshore Norway.

19. The Iranian gas pipeline project, which is presently being considered, would need a price (at the Bulgarian border) of approximately $2/MMBtu to be commercially viable. However, in order for new Norwegian North Sea gas projects to be developed, border gas prices of between $2.85 and $3.20/MMBtu would have to be offered.

Future Challenges

20. The economics of Eastern Europe appear to face an impending gas supply deficit. For reasons of technical and commercial risk management it seems desirable for them to diversify their gas supplies by purchasing from suppliers other than the Soviet Union, thus developing a portfolio of gas purchase contracts from a variety of sources. However, for technical and other reasons, gas supplies from North Africa, the Middle East and in particular Norway are likely to cost more than gas supplies from the Soviet Union. This is firstly because the costs per cubic meter of gas of developing the fields and pipelines are higher, secondly because the gas companies will be obliged to pay in hard currency, and thirdly because "sellers market" conditions may prevail over the next decade, and border prices are expected to be "bid up".

21. Accordingly, the gas companies of Eastern Europe face several challenges, and need urgently to consider their strategies. Huge amounts of capital must be invested to make incremental gas supplies available. It seems unlikely that sufficient funds can be generated within Eastern Europe. Some external funding is, therefore, likely to be required. While institutions such as the World Bank, EBRD, EIB, IFC, etc. clearly have a role, private sector sources of funds are also likely to be required, both from the financial community and also in the form of equity finance from Western companies. To the extent that financing cannot be obtained on attractive terms, or cannot be obtained on a timely basis, Eastern Europe's gas market will be supply constrained, with potentially severe implications for the environment and for the region's economic and industrial development.

22. There are a number of other important items, in addition to financing, which must be addressed by Eastern Europe's gas companies as they seek to secure gas from non-Soviet sources: namely, whether cooperation with other regional gas companies, or with Western oil and gas companies is desirable in order to facilitate gas purchase and/or infrastructure development; whether the premiums, which are likely to have to be paid for supply diversification, can be supported by gas users; whether high levels of take-or-pay commitment can be supported by gas users; and whether consumer prices for gas accurately reflect the true economic cost of gas supply.

I. Key Issues in Implementation of a New Natural Gas Supply Strategy for Eastern Europe

A. Introduction

1.1 In this report, we aim to describe the current role that natural gas plays in the energy balances of Eastern Europe, and to identify its future potential. We will also consider the key policy issues that need to be addressed in developing natural gas supply strategies, both at the regional and national level. For such issues to be developed within an appropriate context, it is vital that national policy objectives are clearly understood and made clear to potential investors, and that the full implications of policy measures to be implemented in order to meet set objectives are considered.

1.2 To facilitate the review of these issues, the central importance of the regulatory framework in which the (public and private) gas production, transmission and distribution entities will operate is considered, together with the role of government in creating the environment in which a gas policy can be successfully executed. The role of the private sector as well as other agencies and financial institutions is also addressed, as is the potential for private ventures. At the regional level, the need for greater cooperation is discussed, together with the importance of a proper institutional framework in which regional issues can be reviewed and opportunities for collaboration established. Finally, some areas for potential regional initiative are indicated.

B. Assumed Policy Objectives

1.3 In seeking to consider the key issues in implementation of a new natural gas supply strategy for Eastern Europe, it is assumed that all governments in the area will set as their policy objectives a combination of:

- Assurance of stable, long-term supply sufficient to meet expected gas demand increases
- Minimization of cost, both capital and operating costs, particularly in terms of foreign exchange
- Maximum reliability of supply in terms of both physical and political interruptions
- Rationalization of supply strategies in the European context.

1.4 Not all governments will give identical weight to each of these elements, but the differences are probably minor, since the structural variances in terms of supply autonomy within the gas economies are relatively modest (with the exception of Romania). Clearly, it will be essential that specific policy initiatives are undertaken that both rectify current weaknesses (for example by providing appropriate incentives for energy conservation via the price mechanism) and create conditions in which these policy objectives can be realized.

1.5 Whilst many such policy initiatives can and should be taken at the national level, there are likely to be significant potential benefits in cooperation at the regional level, not least in terms of:

a) Minimization of transportation and storage costs via access to the economies of scale which are likely to be available to regionally oriented projects;

b) Maximization of supply security via arrangements for supply back-up, as a means of sharing the "insurance premium" associated with supply diversification (an issue which is discussed more fully in Chapter 3, Section D).

1.6 Such benefits would contribute greatly to the rationalization of gas supply strategies within the context of the European gas industry as a whole. It seems inappropriate for a single supplier to dominate the gas availability of Eastern Europe when that supplier may not be the lowest cost supplier. Each of the main suppliers to the European gas industry undoubtedly has a "natural sphere of influence", based on distance to market, which is a significant determinant of costs. But within Western Europe, cooperation between gas companies has permitted a large element of supply diversification to occur in most areas and countries, and there is no reason why the same phenomenon should not occur in Eastern Europe. The integration of Western and Eastern gas infrastructure by physical connection would permit an overall rationalization of gas supply strategies to be implemented.

1.7 Gas companies and the relevant competent authorities must recognize, however, the potential for conflict between short- and long-term objectives. For example, a cost-effective method of enhanced gas supply security is to invest in dual-firing capability in power plants and for large industrial users, thus improving security in the event of a shortage caused by technical or other reasons. But dual-firing tends to reduce the market value of gas in the country in question, by removing part of the premium which might otherwise be charged for gas, and giving it a value equivalent to thermal parity with fuel oil. This undermines the ability of the gas company to offer an attractive price to suppliers at the country's border, and therefore hinders them in achieving the longer term objective of greater supply security via additional suppliers.

1.8 Success policy implementation is likely to require:

- Clear and coherent articulation of the intended strategy to the entities charged with implementation.
- Consistency of policy, with few, if any, changes in objectives, strategy or regulatory framework.
- An appropriate approach to project financing, and, if relevant, to the involvement of private and/or foreign investors.

1.9 Since the focus of this report is on natural gas, issues of general energy policy are not addressed in depth. Clearly, however, it is essential that gas policy is consistent with policies on other energy-related issues, such as, for example, energy pricing policy, which needs to be internally consistent.

1.10 In an open economy, the energy pricing policy should encourage a level of efficiency in energy use comparable with those of competitive economies. This is particularly important where inefficient use of energy has direct balance-of-payments consequences. Naturally, however, such policies cannot be pursued solely in relation to natural gas without the risk of significant distortion in the competitive position of other fuels. Thus, a consistent energy pricing policy amongst all fuels is necessary if natural gas is to play its proper role within the domestic economy.

1.11 It is recognized that this raises complex issues, particularly in relation to domestic fuels. This is especially true for solid fuels, the production and use of which usually have important socio-economic implications. Nonetheless, failure to provide energy consumers with economic incentives that encourage rational use of energy will only, in the long run, exacerbate economic difficulties. The very high specific energy consumption levels which characterize the economies of Eastern Europe to a significant extent reflect the insulation of their economies from the competitive pressures of international energy prices. There is, therefore, the need to put gas policy within an overall energy policy context which is supportive of both broad economic goals as well as a specific role for gas.

C. Potential Policy Mechanisms

1.12 Clearly, the achievement of energy policy objectives, such as the ones outlined above, raises a number of purely domestic policy issues including:

a) Reduction in demand by promotion of energy efficiency (for example, through development of new housing insulation standards, retrofitting of space-heating controls, elimination of heat loss, etc.) and through development of appropriate energy pricing systems which provide consumers with proper information on relative and absolute energy costs and avoid direct or indirect subsidies.

b) Enhancement of domestic supply options through, where appropriate, development of natural gas exploration and production activity. This will require development of appropriate contractual and regulatory terms, including issues of:

   i) Prices paid to indigenous producers; and
   ii) Access to market (including issues of access to infrastructure).

1.13 This is clearly one of the most important policy issues. In order to attract investment in exploration and production, the expected revenue of producers must be attractive enough to compensate (and reward) them for costs incurred and risks taken. To implement these policy options it may be necessary not only to increase gas prices paid to producers to levels comparable to those in other countries (to ensure that opportunities for domestic production are not impeded by inadequate financial incentives) but also to allow producers to contract directly with transmission and distribution companies, based on freely-negotiated terms. Failure to do so will inevitably impede the attainment of basic policy goals.

1.14 One possible pricing model would be to let prices paid to producers reflect the market value of gas to end-consumers, costs of transportation, distribution and storage (plus a reasonable margin to distributors and transporters). This model ensures that producers are paid the maximum price possible while maintaining the competitiveness of gas against other fuels in the end-consumer market.

1.15 Another possible pricing model would be to base gas prices on recovery of costs of exploration and production, plus a reasonable return on capital invested. Producers tend to favor the first of these two pricing philosophies, since it allows them to assume the price risk, for which they are rewarded in times when prices on competing fuels are high.

1.16 Contractual and regulatory terms to be developed should also serve to reduce vulnerability to external supply interruptions via:

- Increased fuel-switching capability and/or prioritization of use, in order to provide a response capacity to ensure continuation of economic activity in the face of supply interruptions, whether accidental or otherwise, and,

- Development, where feasible, of enhanced storage capacity for natural gas as well as, possibly, for other fuels.

1.17 In the same way, economic signals or other processes must be created to enhance these policy options. In particular, the need to enhance fuel-switching capability can be achieved either by use of the price-mechanism (interruptible sales carrying a discount), by fiscal incentives (allowing accelerated depreciation of such investments), or by legislation (requiring certain categories of consumers to have the capacity to switch fuels). The choice of implementing mechanism may also have important implications for other policy objectives. For example, an

obligation to switch fuels under certain environmental conditions could, in effect, require certain types of users to install dual-firing capacity.

1.18 However, achievement of the broad policy objectives set out above may also require consideration of external issues. Cooperative action between countries may, for example, enhance the prospects of achieving policy objectives in a more cost-effective manner than is possible through the pursuit of purely national policies.

1.19 Such measures would include, for example:

a) Optimization of infrastructure, both to increase utilization of economies of scale (for example, in the use of larger diameter gas transmission systems than would be available to a single economy) and in optimization of the use of existing transmission and distribution grids in order to minimize the cost of system inter-connections.

b) Development of increased regional supply security through:

- Reduction of reliance on Soviet resources through the development of a diverse supply portfolio, including, potentially, Dutch, Norwegian, and Algerian gas;

- Enhancement of the capacity to make up any reduction in existing Soviet supply, for example, by providing reverse flow capacity on the existing transmission systems from the Soviet border and the development of improved connections to enable new supply sources to be made available throughout the region; and

- Agreement to provide back-up or stand-by supply in the event of unanticipated reductions in availabilities.

1.20 Whilst these effects might result from negotiations based on normal commercial interests, it seems likely that, in the first instance, government initiatives may be required to catalyze their development. In this context, the Pentagonal/Hexagonal initiative is particularly noteworthy. We anticipate that other collaborative ventures will be established.

1.21 Inevitably, the tensions between the objectives of minimizing the cost and maximizing security of gas supply have to be addressed. Whilst many of the internal policy actions aimed at reducing import requirements can be evaluated primarily or exclusively in economic terms, other policy measures aimed at enhancing security of supply necessarily impose an additional cost on regional gas economies. Typically, supply security imposes a need for redundancy in infrastructure and supply capability. The incentives for cooperative action will be greatest where a demonstrable case can be made that the cost of such redundancy can be, in aggregate, reduced through coordination of activities. As is suggested below, it will be essential, if significant progress is to be made on identifying and implementing such issues, that a clear framework is established in which such evaluation of the potential benefits of collaboration can be identified.

D. Importance of the Domestic Regulatory Framework

1.22 In considering the development of a new gas supply strategy for Eastern Europe, it is difficult to overstate the importance of the domestic regulatory framework, as the main determinant of activity, profitability and risk within the domestic gas industry. The regulatory framework will:

(a) Determine the structure of the market and thus the opportunities for both domestic and foreign entities to enter individual sectors of the business. For example, a horizontal segmentation into production, transmission and distribution functions (as is the case in Germany) would lead to a totally different market structure to the vertical integration

which characterizes France and the UK. The extent to which the distribution function serves the residential sector, for example, as a quasi-regulated utility, while the industrial sector is served by the production and/or import system using 'open access' transmission systems, will create a very different market structure to one which is based on geographical exclusivity as in, for example, the German demarcation system. Thus, fundamental issues of market structure and inter-fuel competition will be determined by the framework of regulation set by government.

It is important to note that, as is implied above, there is no single pattern of industry structure in western Europe. A vertically integrated industry structure, as is the case today in France, and has been the case in the UK, has been seen to create an imbalance of commercial strength between producers and the transmission/ distribution company. Thus, during the 1960s and 1980s, many UK's (UK Continental Shelf) gas producers felt that British Gas' monopsony (single buyer) position allowed it unilaterally to set prices, to the detriment of the exploration and production function. Against this, it is argued that it was not the vertically integrated structure of the industry which permitted this, but the "landing requirement", which, in effect, required UKCS gas producers to sell exclusively to British Gas.

Whatever the potential drawbacks of vertical integration on domestic producers, it is also argued that, where the industry is fundamentally reliant on a single major supplier (as is today the situation in Eastern Europe), vertical integration can balance the monopoly power of the foreign supplier with corresponding domestic monopsony power.

Horizontal integration to achieve the same objective might require coordination with the transmission sector to a degree which can give rise to concerns. Moreover, it implies a degree of regional segmentation which might be undesirable in some countries.

Horizontal integration in the sense used in, for example, Belgium, where regional entities distribute gas and, typically, electricity and water, also raises concern over the effectiveness of inter-fuel competition. Clearly, gas and electricity compete in all applications except motive power and lighting, and creating integrated gas/electricity suppliers could impede the natural development of either fuel.

(b) Determine the ability of the transmission and distribution sectors (including, where relevant, importers) to bear economic risk and so determine the contractual terms which they will be able to offer to suppliers. Accordingly, the capacity of individual entities to act as viable buyers in their own right and, so, to meet internationally-competitive obligations in respect of take-or-pay for natural gas, ship-or-pay for pipeline capacity and so forth, will be determined by the ability of such resellers either to bear economic risks directly or to pass them through to the market. Traditionally, market risk has been assumed by buyers of natural gas, whereas price and production risk has been retained by sellers. For this system to remain viable in Eastern Europe - recognizing that a move towards open access systems in Western Europe might directionally diminish 'competitive' levels of take-or-pay - either the buyers of first instance would need to be viable obligors for the residual liability, or some other form of undertaking would be required to underwrite this commitment.

It is in this area that the potential trade-off between competition and cost is perhaps most visible. An industry able to offer a high level of off take guarantees to a producer, and thus seek to negotiate lower prices, will tend to be both highly integrated and have limited internal competition. For consumers whose ability to switch fuels is restricted, this situation is clearly a matter of concern. On the other hand, a highly internally competitive industry, unable to offer internationally comparable levels of off take

security, is likely, in a period of potential supply deficit, to be relatively unattractive to a supplier as a potential customer.

Accordingly, East European buyers will face intense competition from western gas companies who may be in a better position to offer high levels of take-or-pay, and who may be able to pay premium prices.

This issue is presently being debated within the European Community where, as part of the process of market integration, there is a strong political desire to increase competition within the gas industry. This is leading to measures intended to prohibit national import monopolies, to require pipeline owners to make capacity available to third parties, and to functionally segregate activities such as transmission, storage, distribution, etc.

The current status of the issue of Third Party Access in Western Europe is that a limited form of access seems likely to be introduced in 1993, when nominated companies (mostly gas transmission companies) will have access to transit rights through other transmission companies pipelines. This limited form of open access will be progressively widened, though the precise timetable is not yet clearly defined. By the late 1990s it is possible that many other groups, including indigenous producers and many large users or groups of users, may have access to the transmission grid.

This is a highly-contentious issue and there is a wide range of opinion on the matter. Generally, large industrial consumers and some distributors appear to be in favor of third party access, while transmission companies and some producers are not in favor of it because it would appear to increase business risks without the prospect of increased rewards, and may lead to a higher level of regulation.

The consequences of this on the future of the gas industry within the Community are uncertain and widely debated. It may be that in a period of balanced or excess supply, producers would compete for a greater share of what is widely recognized to be a rapidly growing market, and bid down prices to the benefit of the ultimate consumer. On the other hand, it may be that the process will lead to increased prices (reflecting higher financing costs to compensate for greater market risk), reduced supply security (reflecting a reduced capacity of the industry to support new projects) and consequently lower growth in the market.

(c) Be a primary determinant of the attractiveness of each market both to suppliers and investors. Under a gas supply scenario of potential constraint, suppliers will regard as most attractive those markets which combine the capacity to flow maximum economic rent back to the wellhead with the capacity to bear the highest level of market risk. Suppliers will, therefore, be interested in the way that the regulatory framework affects the value of natural gas in the marketplace, the tariffication of transmission and distribution systems, their capacity to influence sales volumes, and so forth. Equally, potential foreign investors in the transmission and distribution sectors will be interested in the relationship between economic risk and reward which is implicit in a regulatory framework, as well as other fundamental dynamics of market growth and economic competitiveness.

The issue of consumer price formation is clearly critical in determining the attractiveness of a market to producers and resellers, who typically prefer to be allowed to link gas prices to the prices of the fuels with which they compete - the so-called "market value principle". Consumers, however, tend to regard such 'value-based' pricing as incompatible with competition. Equally, transmission system owners and users tend to disagree on the real economic risk associated with such investments and

therefore the appropriate level of reward; the dispute is particularly acute in relation to the treatment of economies of scale. Given the volume of the gas industry, the tension between the tendency towards "natural monopoly" and the need to engender effective competition needs to be addressed. However, such a balance needs to be reached in the context of broad economic policies: a high degree of price regulation in the gas industry could, for example, be inconsistent with liberal free market principles.

1.23 The role of government (national, regional or supra-regional) will be to correct any imbalance between the economic obligations required to meet broad policy objectives and the ability of the gas industry (whether publicly or privately-owned) to meet these requirements. Clearly, to the extent that, for example, buyers are unable to provide adequate off take guarantees or to assure payment in foreign exchange up to the level of 'competitive' supply agreements, others will be required to do so. Thus, to this extent, government acts as the `balance wheel` of the gas industry. In this context, "government" could mean international agencies such as the EEC, EFTA, IEA, UNECE, etc.

1.24 In determining an appropriate regulatory framework, the following questions need to be addressed:

- What is the mission of each phase of the domestic gas industry (production, transmission, storage and distribution), and how is this mission translated into specific responsibilities and objectives ?

- What economic and non-economic risks does each segment bear and what rewards are appropriate to these risks ?

- Are the current 'players in the gas industry' fully equipped to meet their mission and to bear the relevant risks ? If not, in what ways are they deficient ? If deficient, what steps need to be taken to overcome this ?

- Is the allocation of risk and reward inherent in the proposed regulatory framework compatible with suppliers' concerns?

- Can the economy in question offer a basis for a contractual arrangement which is attractive in the light of the anticipated supply/demand balance and other opportunities open to the supplier in question? If not, what changes are politically, economically and socially acceptable to remedy this deficiency ?

1.25 Clearly, the historical development of the gas economies of Western Europe have led to a number of such models emerging. On the one hand, for example, France has traditionally operated its gas industry in effect on a cost recovery basis, creating a fully integrated monopoly/monopsony entity in Gaz de France, whereas the German system of private sector companies operating in a horizontal segment within a demarcated area on a profit maximizing' basis represents the antithesis to this approach. In the UK, it was widely regarded as implicit policy that, until the early 1980s, British Gas would charge opportunity-cost based prices to industry and simply recover the balance of its costs in the residential sector; in Belgium, on the other hand, there is some evidence that the residential sector has been regarded as being able to bear a high proportion of investment costs in order to keep industrial competitiveness at a high level. With the move towards completion of the internal European energy market, a degree of convergence appears likely, in the sense that the combined effect of a reduction in import monopolies, coupled with tax harmonization and moves towards open transit pipeline systems, is likely to remove some of the more basic differences between market structures. However, some differences are likely to persist.

E. The Role of Government

1.26 Classically, in developing a natural gas supply strategy, there are four types of governmental action which have an important bearing on industry structure and gas market penetration. These are government actions to:

- Set terms for natural resource development, in particular for gas exploration and production.
- Determine the regulatory framework within which the gas industry operates in the context of national economic policies and programs, and determine the relative competitiveness of fuels through fiscal levies.
- Consistent with the above, bear social/political risks and costs to the extent that it is not the mission of the gas industry to bear these costs.
- Influence specific commercial decisions by the gas industry in a manner consistent with overall national economic priorities.

1.27 As such, these government functions are not different to those in other sectors of a market economy. Differing implementation reflects the longer term commitments typically entered into by the natural gas industry, and the historical allocation of risks and rewards which have seen the market risk essentially borne by gas buyers.

F. The Role of the Private Sector

1.28 The role of the domestic private (i.e. non-state) sector is likely, in the first instance, to be limited both by lack of financial capability and, to a lesser extent, by the absence of an effective competitive framework. Both these deficiencies can, in time, be remedied, if attention is given to financial and organizational restructuring, coupled with management development programs.

1.29 As such, the domestic private sector can develop as the basis for a strong domestic gas industry, provided it is given a clear mission and objectives, and the resources to achieve them. Clearly, the domestic private sector is likely to remain, in the first instance, in the ownership of local, rather than central, government, unless ambitious privatization programs are followed. Whilst, in certain instances (e.g. TransGas in the CSFR), privatization may be achievable in the near term, in other cases the introduction of private capital could take much longer. It is here that the role of the foreign private sector is of interest, both as a provider of capital and as a source of technology and management expertise.

1.30 Under attractive regulatory frameworks, considerable interest is likely to be shown in privatization of East European transmission and distribution operations. However, it will be necessary to draw a judicious balance between the national interest and the need to create terms which are attractive to foreign investors.

1.31 In Western Europe, the role of Government varies considerably between countries. In France, Italy, Spain and Denmark the Government has a large role in the gas industry as the owner of the gas transmission company and as regulator of the gas industry has a high degree of influence over such issues as gas pricing. In Germany the gas transmission industry is largely in private hands, though local Government is involved in the gas distribution industry. The Netherlands features a partnership between private companies and Government in the transmission phase. Each country has a unique structure, reflecting the history of the gas industry in that country, the amount of indigenous production and the level of import dependence, the maturity of the industry, the general business culture and other factors. Accordingly, each gas company tends to have a unique

culture and mission, exemplified in its commercial relationships with other parties. Some see themselves as a "national utility", seeking to minimize costs. Others see themselves as merchants, seeking to maximize profits. This tends to reflect the degree of Government involvement in the industry, via ownership and the degree of competition in the energy industries generally.

1.32 In Western Europe, only the United Kingdom has so far privatized the national gas company (i.e. transferred it from state to private ownership). Other countries in Western and Eastern Europe, and on other continents, are considering whether, and if so how, to privatize their gas industries. Drawing on experience in the UK, it is clear that it is necessary for the shareholder (usually the Government) to establish a clear set of conditions (or regulatory regime) for the newly-privatized company (or companies). The shareholder must also consider carefully the desired structure of the gas industry. Should gas production, transmission and distribution be handled by different companies, or by a single company? Should transmission, storage and distribution be integrated functions, or segmented ? Should companies cover the national territory or be given regional responsibilities ? What monopoly rights should be permitted and how should such monopolies be regulated?

1.33 The regulatory and institutional structure of the gas industry should preferably be defined before privatization takes place, as attempts to modify the regulations or industry structure post-privatization can be extremely complex, both from a legal and from a practical point of view. Some countries may wish to remove legal (de jure) monopoly privileges: this may not be sufficient to remove de facto monopoly situations in areas where a particular company has a dominant position. Governments must consider such issues carefully.

1.34 With respect to methods of privatization, there are several potential models. Firstly, Governments must consider whether they wish to partially or wholly privatize the gas industry. If partial privatization is the chosen option, does this mean that Government will retain an interest in each aspect of the gas industry, or will it privatize entirely one phase of the business (e.g. gas production) while retaining full ownership of other phases (e.g. transmission, or distribution)? Having decided what to privatize, the Government must then decide how to privatize. Several models are available. The Government could "auction" the industry, as a whole, or in parts, to the highest bidder, or it could negotiate with a selected list of companies in order to achieve a satisfactory outcome (but not necessarily to maximize price). Alternatively, shares could be sold to private individuals, financial institutions and trade investors. In selecting the most appropriate method of privatization, Government will wish to consider its attitude to foreign ownership (including repatriation of profits and dividends), corporate control and other related issues.

1.35 A particularly important issue in the context of the East European gas industry, and one which requires resolution prior to any potential privatization, is to establish which party, or parties, owns the gas industry today. In some countries, the working hypothesis may be that the state or regional Governments own the gas industry: in others, the employees may be considered to be the owners. This issue is important because of the need to determine which party, or parties, should receive the proceeds of privatization.

1.36 Restructuring the gas industry, including possible privatization, may have many benefits. There may be considerable benefits in creating a number of companies specializing in a particular phase of industry, to facilitate management and the appropriate allocation of corporate resources - financial, human and technical. This would allow companies which may currently be monolithic, but having a large number of diverse activities, to specialize in a small number of highly-related activities. For example, gas pipeline construction and engineering activities could be carried out by a specialist company acting as a contractor to the transmission company, rather than being conducted in-house. By specializing and focusing, experience will be gained more rapidly and costs can be reduced. Restructuring may also bring benefits such as avoidance of duplicated activities; reducing the number of layers of managers between the operating companies and the executive functions; managerial and financial autonomy - being able to raise finance independently

and not having projects being conditional on internal funding. Privatization may bring benefits - not only of restructuring - but also by facilitating technology transfer from foreign shareholders, and improving the ability of the gas industry to fund investments. Depending on the regulatory regime, it may also allow companies to determine sales prices more freely, and to manage their costs more effectively.

G. The Need for a Commercial Attitude

1.37 In this context, the interface between, and possibly conflicting aims of, social and economic policies are of interest and need to be addressed. One such issue is the often quoted need to foster a more commercial attitude among East European gas industry participants.

1.38 The question arises: what is a "commercial attitude", is it desirable and how can it be promoted effectively and how can it be promoted effectively? By commercial attitude we are referring to the endeavors of:

- Companies (whether publicly or privately owned) to maximize the benefit to the organization and its owners (normally in profit terms), to operate and allocate own resources as efficiently and effectively as possible (thus minimizing costs, maximizing benefits and maintaining a professional corporate image), and most importantly to respect the objectives and policies pursued by business partners and by the government (in so far as these are known or can be anticipated).

- Government to maximize the benefits to society at large, to allocate national resources and to implement policies as effectively and as efficiently as possible, and to respect and support the objectives and policies pursued by industry, where these do not conflict with the interests of society.

1.39 The key ideas here are not only "maximization of own benefit" but also "respect for the objectives and policies of others". Only in an environment where such respect is present can fruitful negotiations be held, common ground established and solutions which benefit all parties be found.

1.40 The question of whether a commercial attitude is desirable or not is clearly a political one. In the end, the answer will depend on whether its potential consequences are regarded as attractive or not. According to economic theory, the answer to this question is clearly "yes" -in a perfect market economy the fact that companies and consumers all strive to maximize their own benefit, while the government looks after the needs of society at large, results in progress - everybody gets better off all the time. Few of us are, however, living in perfect economies. Economic realities and relationships are mostly too complex to be transparent enough to permit a simultaneous maximization of benefits on all sides. In addition, the economic environment is not static but subject to change, reducing our possibilities to comply with the theoretical economic behavior of rational individuals and organizations even further. In so far as there is a risk of expected commercial developments deviating from the overall interests of society (the nature and contents of which will be decided politically), it may be necessary for the government to assume a balancing role to safeguard those interests, carefully weighing the benefits and drawbacks of free enterprise and competition against those of increased regulation and control.

1.41 To summarize, a commercial attitude is, in principle, desirable from a societal point of view. Its actual and potential impact on economic, industrial and social development should, however, be monitored, and appropriate action be taken to encourage desirable, and discourage undesirable, consequences as and when necessary.

1.42 If it is decided that a more commercial attitude is desirable, the next question is, obviously, how it can be developed. In addition to longer-term actions like education and supporting legislation, the Government can encourage its development by providing the necessary industrial and environmental conditions as well, as itself adopting and displaying a commercial attitude through:

- Active promotion of competition and free enterprise
- Active promotion of private and decentralized ownership
- Encouragement of free commercial negotiations once the legislative and regulatory framework is in place
- Refraining from market interference and re-regulation.

H. The Role of Other Agencies

1.43 An important role can be played by other agencies (such as the EEC, EFTA, EBRD, IFC, UNECE, etc.), as a potential source of funds for projects which have a strong national interest. However, such projects may have limited commercial appeal (for example, system interconnections to improve security, reverse flow capability for the same reasons, strategic storage projects and so forth). In addition, such agencies can provide a neutral forum for discussion both of inter-regional projects and public/private sector developments.

I. The Role of Financial Institutions

1.44 Discussions with financial institutions suggest that the commercial lending agencies are becoming increasingly concerned about project financing for gas developments, particularly for production projects and transportation projects which are in areas of current, or likely future, regional conflict. Accordingly, although commercial funds may be available to support large scale investment in Norway, with a relatively low level of equity investment therefore being required, it is unlikely that such institutions will be willing to support large scale investments in the USSR, parts of the Middle East, and possibly North Africa. Commercial sector support for a Yugoslavian LNG terminal and pipeline would be extremely unlikely to be forthcoming. This suggests that alternative sources of finance must be required. There are several possibilities:

1.45 *Equity.* If the banking community is unwilling or unable to advance the necessary funds for such projects, additional equity will be required. To the extent that local currency investment is required in Eastern Europe, the necessary equity funds can probably be made available relatively easily. If hard currency investments are needed, Hungarian entities may be obliged to turn to Western partners such as Total, BP, Shell etc. Such partners may be willing to invest but may seek access to local markets in return: for example, they may seek part of the shares of MOL or other Hungarian entities in return for becoming involved in the project. The costs of financing projects will clearly be higher where a larger amount of equity finance is required, because the investor bears more of the project risk. The level of risk borne by investors will also be influenced by the degree of assurance of off take which buyers are able to offer. As the Hungarian transmission system now permits third party access, MOL may not be in a position to offer high levels of take-or-pay to suppliers, who may therefore seek a higher price for the gas.

1.46 *Multilateral aid agencies.* Several agencies may be in a position to offer support to the East European gas industry in its efforts to enhance the level of supply security via diversity, including the World Bank. Perhaps the most obvious other candidates are the European Bank for Reconstruction and Development, and the European Investment Bank. These agencies have

traditionally lent to state-owned enterprises. Others, such as the International Finance Corporation, have lent only to the private sector. This restriction is beginning to break down, with the World Bank now being able to support private sector initiatives.

1.47 ***Export credits.*** Many Western Governments are willing to provide a measure of financial support for projects by guaranteeing payment to equipment suppliers. Project investors have therefore been able to purchase equipment on less onerous terms than would otherwise have been the case. The best-known European export credit agencies are ECGD (United Kingdom), Coface (France), Saice (Italy) and Hermes (Germany). Various non-European countries have Ex-ImBanks which also offer support for such projects.

1.48 ***Direct and indirect Government support.*** In the absence of other parties which are able and willing to accept risk, the party of last resort is likely to be Government. Only Governments tend to have the necessary financial strength and influence to be able to support certain projects: for example, they can "internalize" some of the commercial risks via appropriate regulatory mechanisms, such as by intervening in gas pricing issues they can remove market and/or price risk. Or they can directly invest in projects: the Belgian Government invested directly in the Zeebrugge LNG terminal, for example.

1.49 ***European energy charter.*** The current discussions with respect to the European Energy Charter, which are expected to continue through the early part of 1992, may provide the basis for facilitating technology transfer and inward investment into energy projects in Central and Eastern Europe and the USSR. This may enable greater amounts of private capital to be mobilized to support the development of the necessary gas infrastructure and to underwrite the financial risks associated with long-term gas purchase agreements. In this way, the creditworthiness of Central and Eastern European gas companies would be improved and they would become more attractive customers for the suppliers.

J. The Institutional Framework

1.50 A number of formal and informal groupings have developed in recent months to address a number of these issues, usually in the context of specific projects. Whilst such discussions are helpful and constructive, a broader institutional framework is likely to be necessary to address a number of key interregional policy issues. Such an institution could arise from the Hexagonal Initiative, for example, or have a quasi-permanent secretariat charged with responsibility for energy or gas issues.

1.51 These are likely to focus on consideration of two key issues, namely:

- How inter-regional supply costs can be minimized, and security of supply maximized, and
- The extent to which governments in each economy are likely to use common criteria in addressing such options and choices.

1.52 Clearly, the first set of issues is broadly one of information gathering and dissemination. The second, however, is more fundamental to policy determination, since opportunities for collaboration are likely to be determined by the extent to which common policy goals and objectives exist and can be evaluated on the basis of common criteria.

1.53 Such an institution might be in a position to assist its members deal with issues relating to collaboration in new gas purchase and infrastructure projects, and permit the necessary trade-offs to be achieved in order to balance the costs and benefits between the participants on the buying

side. On such a basis, a rational set of import options could be assembled, gas swaps arranged, gas transmission systems and supply arrangements optimized, etc., to the benefit of all.

1.54 Furthermore, such an institutional framework might allow governments to do more than facilitate the process of developing a new gas supply strategy, and allow pro-active consideration of regional projects of considerable social and political interest (such as strategic storage) which might have limited economic appeal to private capital. The structure, procedures and responsibilities of such an organization would require further review. It would be inappropriate to seek to identify how such trade-offs as may be necessary should be evaluated and resolved. This is clearly a matter for the parties concerned.

K. Opportunities for Collaboration

1.55 It is apparent that a significant number of potentially collaborative opportunities exist. These include:

a) Joint infrastructure development, including:

- Seasonal and strategic storage, possibly in depleted gas fields, aquifiers or salt domes.
- System inter-connections, both to improve the flow of gas from existing sources, and to enhance the supply option from new potential sources (for example, by providing reverse flow capacity).
- Blending and treatment facilities, to allow admixture of different gas streams.

b) Joint purchasing, to achieve potential economies of scale in infrastructure (in the case of LNG, receiving terminals and pipelines) and to provide the rapid build-up to substantial volumes which new suppliers will regard as desirable in justifying new supply projects. For example, gas companies could form ad-hoc consortia for the purchase of Norwegian or Algerian gas, such as the Hexagonal Initiative.

c) Intra-regional trade and security agreements, under which fuel substitution programs would allow gas to be diverted under pre-determined conditions, to areas which might face supply interruptions, whether for accidental or other reasons.

1.56 However, certain other key issues will need to be addressed, including:

- The possibilities for intra-regional competition to attract foreign (external) capital and technology, and
- Intrinsic differences in industry structure, profitability or creditworthiness, which might impede intra-regional collaboration.

L. Contractual Issues

1.57 Gas purchase contracts are a means of allocating risk and reward between buyer and producer. There are three principal types of risk:

- Geological risk, which is taken by the buyer in a "depletion contract" (the buyer agrees to buy all of the gas in a particular field), and which is taken by the seller in a "supply contract" (the seller agrees to deliver a specified volume of gas over a given number of

years). Potential suppliers to Eastern Europe can be expected to sell gas under "supply contracts".

- Market risk, which is normally taken by the buyer, who is likely to be required to agree to a high level (80 or 90%) of "take-or-pay": in other words, to guarantee payment for a substantial proportion of the gas regardless of whether there is a market for it when it is deliverable.

- Price risk, which is normally taken by the seller.

Various contractual mechanisms have been devised to share risks. For example, in the 1970s, buyers were requested to take most of the price risk by suppliers, by agreeing to a "floor-price" - a minimum price for the gas.

1.58 The type of contracts likely to be sought by Norwegian, Algerian or other suppliers can be expected to differ significantly from those historically available from the USSR to Eastern European buyers. Such suppliers are likely to require the following types of terms:

- 20 years supply agreements

- High levels of "take-or-pay": probably 80-90%

- High load factor off take (7000-8000 hours p.a.)

- Payment in US dollars or Deutsch Marks

- Three-yearly price reviews

- Escalation of the gas price on a quarterly or monthly basis, referenced to petroleum products

M. Key Issues

1.59 It is suggested that the key technical issues to be addressed include:

- What technically and economically feasible supply options exist with broad regional appeal ?

- What realistic capital, technical and human resources constraints exist on the development of regional gas expansion ?

1.60 The key political issues which might be addressed include:

- What level of "insurance premium" is appropriate and reasonable, to achieve supply diversity ?

- How might this be allocated on a collaborative intra-regional basis ?

- What steps need to be taken to proceed better to explore such opportunities ?

1.61 Each company and country has unique characteristics, but each shares the wish to enhance gas supply security, probably via diversity. It is not the purpose of this document to recommend particular strategies: rather, it is intended to provide a basis for establishing the extent to which collaboration is desired and is considered feasible, and to identify the necessary next steps. This may involve the formulation of gas purchasing consortia, or consortia for developing infrastructure.

1.62 The main supply diversification options are to purchase gas from Algeria (via pipeline or in the form of LNG) and from the Middle East (via pipeline or in the form of LNG). Each of these options (and others) is discussed in more detail elsewhere in this document, in the context of individual countries.

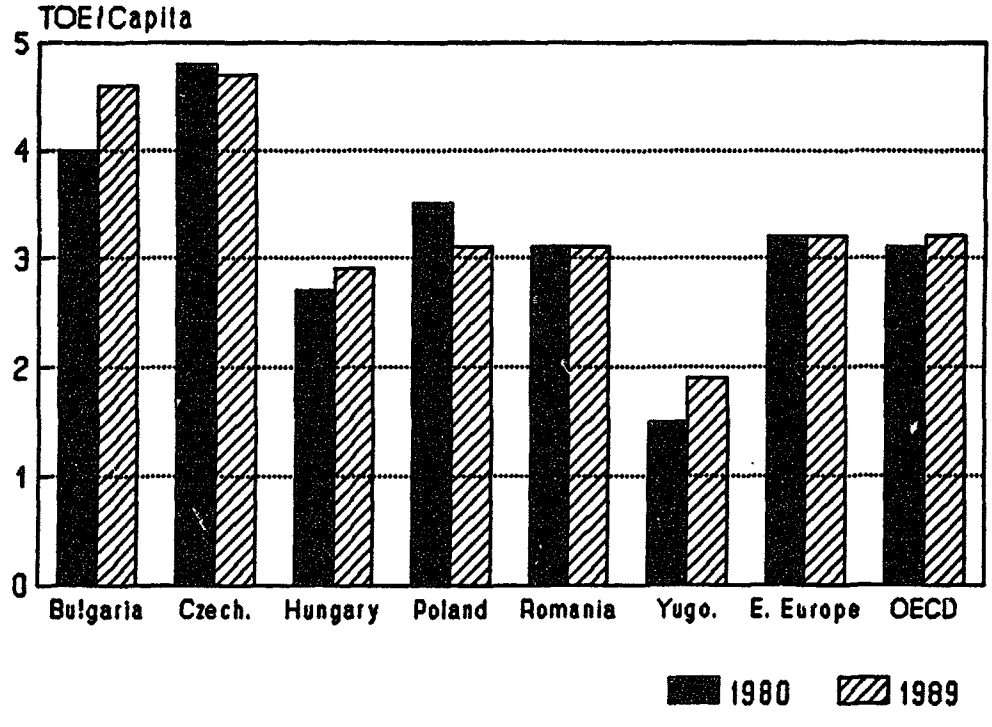
II. Current Energy Balances and the Role of Gas

A. Primary Energy Supply and Demand

2.1 This section discusses energy supply and demand in six East European countries (Bulgaria, Czechoslovakia, Hungary, Poland, Romania, Yugoslavia) as a region. First, we will examine energy demand per capita, then analyze historical energy demand by sector and energy supply by fuel, and finally specifically assess the historical role of gas. Changes in energy demand will be described and differences between countries emphasized.

2.2 Primary energy demand per capita. The six East European countries are very different in terms of industry structure, indigenous energy resources, population, etc. It is therefore difficult to analyze the historical energy demand of the region as a whole, without making references to the characteristics of individual countries, or to compare individual countries. However, an estimate of historical energy demand per capita provides an indicative measure of energy use adjusted for the size of the country and its economy (in terms of population).

Chart 2.1: Primary Energy Demand Per Capita

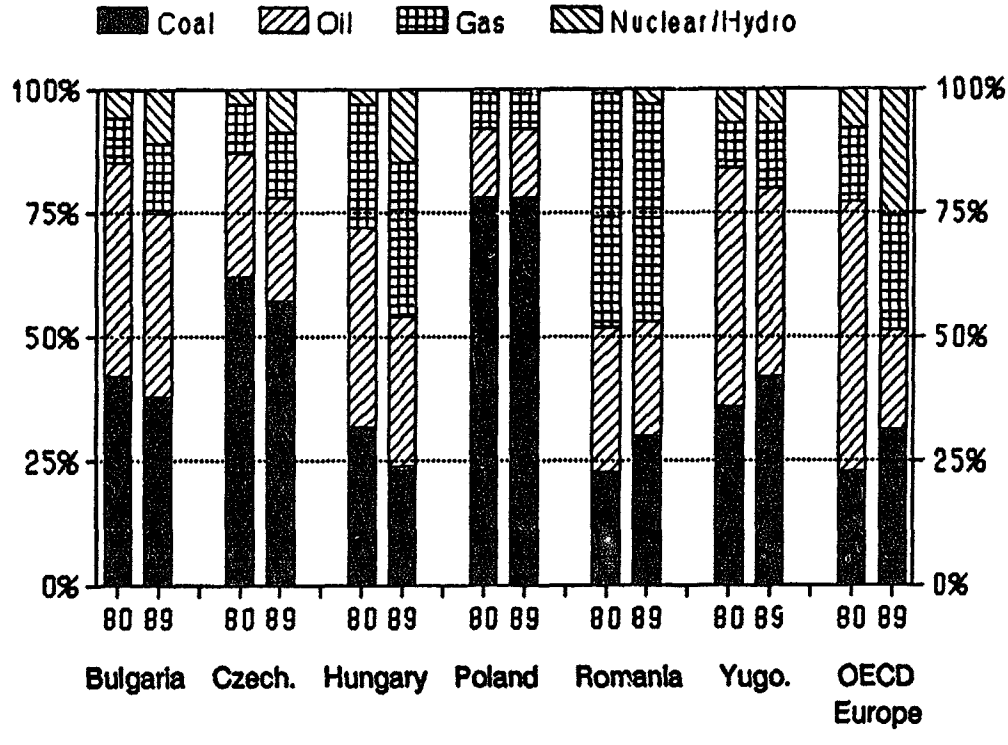


source: International Energy Agency

2.3 Czechoslovakia and Bulgaria have the highest energy demand per capita, the former consuming almost 4.7 tonnes of oil equivalent (toe) per capita and the latter about 4.6 toe per capita. Poland and Romania rank next at about 3.1 toe per capita, while Hungary is slightly lower at 2.9 toe per capita. Finally, Yugoslavia has the lowest energy consumption per capita at about 1.9 toe. Over time, none of the East European countries have showed significant changes in per capita energy consumption relative to Western Europe, indicating that there is scope for energy conservation. A modest increase in energy consumption per capita was seen in Yugoslavia from 1980 to 1989, while only slight increases were registered from 1980 to 1989 in Bulgaria, Czechoslovakia, Hungary and Romania. A decline in energy consumption per capita was registered in Poland.

2.4 In comparison with OECD Europe, the per capita energy consumption of the six East European in total in 1989 was approximately the same, at 3.2 toe. The similarity in per capita consumption is explained not by comparable energy use but by the considerably lower use of transport fuels per inhabitant (0.6 toe per capita in OECD Europe compared with 0.3 toe per capita in Eastern Europe). Per capita energy consumption has remained relatively constant in both areas during the 1980s.

Chart 2.2: Primary Energy Demand by Fuel



Source: International Energy Agency Statistics, United Nations

2.5 The six countries show several similarities to each other in terms of their energy fuel mix, in comparison to OECD Europe and the way in which it seems to be developing. Among these similarities are a continued reliance on coal, which in most cases has a share of primary energy demand well above that of OECD Europe. The share of oil, which reaches levels similar to those of OECD Europe only in Romania, has been declining in all countries from 1980 to 1989; while natural gas has increased slightly (except in Romania, where it is declining due to the drop in indigenous gas production).

2.6 Three factors help to explain these trends. Firstly, coal is an indigenous resource and reserves are large. Hence, use of coal does not require hard currency expenditures. Moreover, the dominance of coal has further been enhanced by a lack of pollution control, an issue which is now beginning to be addressed. The use of coal also satisfies social and political employment objectives and has provided a least cost alternative to nuclear power, which, since the Chernobyl accident, may have become less acceptable.

2.7 Secondly, oil use has declined as a result of the continued stagnation and general contraction of the East European economies. In particular, growth potential in transport fuels such as motor gasoline, jet and diesel has been limited by the employment of consumption restriction measures. In addition, supplies have been constrained, since the Soviet Union has capped or reduced oil supplies to Eastern Europe in favor of increased supplies to Western buyers.

2.8 Thirdly, the share of natural gas in primary energy demand has increased slightly despite constant indigenous production. An overall growing demand has led to increased imports from the Soviet Union.

2.9 ***Coal demand and supply.*** Coal use and trade in Eastern Europe is dominated by Poland. About 80 per cent of Poland's own total energy needs are satisfied by coal, a proportion that has remained constant since 1980. In addition, Poland, along with the Soviet Union, is a significant hard coal exporter to other East European countries and the West. Poland's coal exports are mostly high quality hard coal, and, as such, have the potential to help both Poland and the surrounding countries to meet future growth in energy demand and in improving the environment. The coal used within Poland has, so far, however, been of low quality. Exports to both Eastern Europe and the West are expected to continue in order to provide Poland with a major source of hard currency.

2.10 The Czechoslovakian energy supply mix is also dominated by coal, which accounts for around 60 per cent of total supply. However, Czechoslovakian coal is almost entirely low quality, and recent environmental concerns may prompt a reduction of coal's share of energy supply in the future. In an effort to alleviate quality concerns, Czechoslovakia trades brown coal for lower sulfur hard coal from Poland.

Table 2.1: Primary Energy Demand by Fuel

MTOE	Oil	Gas	Coal Hydro	Nuclear/	Total
1980					
Bulgaria	15.4	3.2	14.8	2.2	35.6
Czechoslovakia	18.6	7.3	45.7	1.8	73.4
Hungary	11.5	7.2	9.2	0.7	28.6
Poland	17.9	8.8	97.6	0.3	124.6
Romania	19.9	32.4	15.5	1.1	68.9
Yugoslavia	16.1	3.0	12.0	2.4	33.5
1989					
Bulgaria	15.4	5.6	15.8	4.4	41.2
Czechoslovakia	15.2	9.2	41.2	7.0	72.6
Hungary	9.2	9.4	7.2	4.6	30.4
Poland	16.1	9.1	93.2	0.5	118.9
Romania	17.0	32.3	21.6	1.8	72.7
Yugoslavia	16.5	5.8	18.5	3.2	44.0

Source: IEA Energy Statistics

2.11 The other four countries (Bulgaria, Hungary, Romania and Yugoslavia) have a more balanced energy supply mix in which the share of coal ranges from about 25 per cent to about 40 per cent. The quality of coal in these countries is a major concern, as the use of it causes significant problems with sulfur and particulate emissions. All Eastern European countries have indigenous coal production, with only Bulgaria being a net importer of coal.

2.12 ***Oil demand and supply.*** Broadly speaking, East European countries during the 1980s acted to increase the use of natural gas (imported from the Soviet Union) and to develop nuclear power stations. The reasons were on the one hand the intention to reduce the reliance on relatively expensive Soviet oil imports, and on the other the absence of a real alternative, since the supplies of oil from the Soviet Union were constrained, and often temporarily curtailed in favor of

Western buyers. However, after the Chernobyl accident the majority of nuclear plans were dropped and oil imports (particularly for use in power generation) continued.

2.13 East European countries are unprepared for any significant growth in oil demand. While selected countries have limited indigenous crude oil resources, the refining and distribution systems have generally not been well maintained and will require substantial investment. Furthermore, the lightening of the demand barrel (characteristic of the growth of transportation fuel demand), and increased use of natural gas, will require refinery upgrading and investment in new downstream residual processing units. Additional investment will also be required at the distribution and retail levels.

2.14 The countries which appear most prepared for changes in oil demand are Hungary and Romania. Both countries have indigenous oil reserves and are currently producing oil, though neither is self sufficient. Moreover, Hungary has seen a decline in oil demand during 1980-89, a trend which is expected to continue, albeit at a slower rate in the future, thereby reducing dependence on declining and unpredictable Soviet supplies.

2.15 In fact, oil demand has declined in the whole region, except in Romania, where domestic reserves and production are quite large. The decline in oil demand occurred almost entirely in the early 1980s, and has since 1986 remained relatively constant.

2.16 ***Hydro and nuclear electricity.*** Hydro and nuclear power accounted for about 6 per cent of the region's primary energy supply during 1989, up from 2 per cent in 1980. Selected countries such as Yugoslavia have significant hydro resources but are severely limited by development and infrastructure investment costs. During the next ten years, hydro developments are expected to increase somewhat (through the help of institutional loans) but capital constraints will continue to place downward pressure on any significant expansion. The future of nuclear power programs in many East European countries is uncertain and moratoria have been placed on new construction projects. Apart from the public opposition resulting from the Chernobyl accident, many countries would have technical and economic difficulty with expansion of nuclear plants without the assistance of the Soviet Union.

B. Historical Natural Gas Supply and Demand

2.17 Eastern Europe has become increasingly reliant on natural gas resources both from indigenous and imported sources. Although the share of gas in primary energy demand has not increased significantly overall (only rising from 17 to 19 per cent from 1980 to 1989) gas demand increased by an average of almost 2 per cent per annum. This suggests that gas demand growth has satisfied incremental demand rather than displaced other fuels. More importantly, incremental demand was satisfied by additional imports from the Soviet Union, which rose by an average of 7 per cent per annum during 1980 - 1989. During the same period, indigenous production in the region as a whole declined from 45 to 40 BCM.

2.18 East European gas consumption is concentrated in the industrial (including petrochemical) and power generating sectors. Pipeline transmission and distribution systems are established in most of Eastern Europe, permitting the residential and commercial sectors to consume about 20-30 per cent of total gas demand.

2.19 The Soviet Union exported over 60 BCM of gas through Eastern Europe to Western Europe in 1989. In addition to that, the countries which originally constructed the pipelines were compensated with gas which served as a transit fee. Now that the pipeline infrastructure is in place, there is limited potential for many East European countries to increase gas imports from the Soviet Union to the level that is required to meet future demand unless existing pipeline capacity is expanded or new infrastructure added.

C. Gas Infrastructure

2.20 The natural gas pipeline networks of Eastern Europe show varying degrees of development and market coverage. The gas markets of Czechoslovakia, Hungary and Romania are relatively well covered while Bulgaria, Poland, and Yugoslavia have relied more heavily on other fuels and therefore have less developed gas pipeline networks. In some countries, infrastructure was developed to distribute indigenously produced gas, while in others networks were developed mainly to import or transit Soviet export gas.

2.21 In all countries, there is a need to invest heavily in refurbishing existing pipelines and replacing compressors, and extending the transmission and distribution systems. In particular, it would seem desirable to construct a series of relatively short pipelines to link the systems of neighboring countries where these are not already in place, provided, of course, that the economics of such projects are favorable. The purpose of such pipelines would be to provide additional supply security in the event of technical difficulties as other parts of the system age and are refurbished.

D. Major Gas Purchase Contracts

2.22 In 1990, Eastern Europe imported 45 BCM of gas from the Soviet Union. Gas import contracts between former Comecon countries and the Soviet Union differed from their Western European equivalents in that they were rolling contracts, i.e. valid for five year periods after which they were automatically renewed, although with price and volume adjustments. Imported gas was usually payable either in transferable rubles, which in some cases could be translated into bartered goods. We believe that the rates at which rubles were translated into barter goods differed between the individual countries.

Table 2.2: Major Gas Purchase Contracts with the Soviet Union

Country	Contracts	Annual Volume BCM[a]	Deliveries Began	Deliveries to End	Duration Years
Bulgaria	I	2.9	1976	n/a	
	II	2.7	1980	n/a	
	III	n/a	1989	n/a	
Czechoslovakia	I	2.7	1980	1991	12
	II	4.75	1995	2005	17
Hungary	I	2.7	1979	1992	
	II	1.9	1989	1998	10
Poland	I	2.7	1979	1998	20
	II	2.7	1989	1998	10
Romania	I	1.5	1979	n/a	12?
	II	(1.5?)	1989	n/a	
Yugoslavia	I	11.3	1991	2005	15

Source: Arthur D. Little

a. Billion standard cubic metres @40 MJ/m3

2.23 Gas was in many cases also supplied under separate agreements as compensation for pipeline construction services rendered to the USSR or, in the case of Czechoslovakia, Hungary

and Romania, as transit fees. Earlier this year all contracts were converted to hard currency terms, resulting in a substantial price increase. It has been indicated in the press that the Soviet Union is now considering formally going back to contract forms allowing barter payments, as very few cash payments for gas have in reality taken place since the conversion to hard currency (though they have for oil).

Table 2.3: USSR Export Gas Prices

$/MMBTU	1975	1980	1985	1986	1987	1988	1989	1991
East Europe	0.27	1.22	2.96	1.79	1.06	0.83	0.91	2.75
West Europe	0.44	0.92	3.49	3.12	2.53	2.08	1.96	2.56

Source: Soviet Energy: An Insider's Account

2.24 Clearly, therefore, gas imports are a major component of Eastern Europe's trade balance. Assuming that the 1991 price of $2.75/MMBtu (equivalent to $100 per 1000m3) applies equally to all East European countries, the total annual import bill is approximately $4.7 billion, or broadly equivalent to 1.1 per cent of East Europe's GNP (at official exchange rates).

E. Industry Structure

2.25 With the exception of Yugoslavia, energy industry structures in East European countries have up to now been relatively similar: large, state owned organizations governed by ministries with control over all aspects of energy production, trade and distribution. Several countries are now in the process of reorganizing and privatizing their gas industries.

2.26 The details of the industry structure for each country are given in the relevant country sections in the appendix to this report. There is no unique model, just as there is no "correct" way of organizing the gas industry. Some countries, such as Poland, have historically had a fully-integrated gas production, transmission and distribution company. Other countries, such as the CSFR and Yugoslavia, are organized on a regional basis.

2.27 Reorganization and privatization of industries is seen as a step in the process of transforming centrally-planned into market economies. The potential benefits to be gained from decentralization/ privatization of ownership and control and introduction of competition are increased inflow of foreign investment, increased economic efficiency, increased international competitiveness, and ultimately a contribution to economic recovery. Whether or not all these benefits will be realized will depend on the ability to attract foreign investment and the speed with which restructuring is able to take place.

F. Potential Contribution of Natural Gas to Environmental Improvement

2.28 Atmospheric pollution poses serious problems in all East European countries. Lack of environmentally accepted technology and awareness have contributed to an increasingly serious level of environmental damage for which corrective measures need to be implemented. The solution of closing down polluting plants and industries and replacing them with environmentally friendly alternatives is, in most cases, not a viable option, because new plant cannot be built sufficiently quickly.

2.29 If natural gas was used to replace coal in power generation, substantial environmental improvements could be achieved. Similar effects could result if new, clean coal technology power

plants were installed. The shortage of capital resources, however, prevents fast progress on this front, which is further obstructed by the lack of indigenous gas reserves and the prospect of long term commitments to increased imports payable in hard currency. Several countries are very concerned and actively seeking solutions to these difficult problems. It seems likely that within five to ten years, some progress could be made towards displacing heavily-polluting fuels, such as lignite, by natural gas, but that it may take between ten and twenty years before the levels of SO_2, NO_x and particulate emissions can be stabilized.

Table 2.4: Potential Increase in Gas Demand in Power Generation

	Electricity From Coal		Potential Gas Fired Capacity GW[a]	Realistic Gas Fired Capacity GW[b]	Potential Gas Burn BCM[c]	Realistic Gas Burn BCM[d]
	TWh	%				
Bulgaria	23	50	3.2	0	4.5	0
Czechoslovakia	47	53	6.7	1	9.4	1.4
Hungary	7	25	1.1	0.4	1.5	0.6
Poland	133	92	18.9	1	26.5	1.4
Romania	31	42	4.5	1	6.3	1.4
Yugoslavia	47	57	6.7	2	9.4	2.8

Source: Arthur D. Little

a. Potential for gas in power generation, measured in terms of CCGT capacity required if all coal-fired capacity was to be replaced (assuming load factor of 60%).

b. Realistic potential for gas in power generation, in terms of estimated CCGT capacity that could be built in the short term (up to 1995, assuming load factor of 80%).

c. Potential gas burn if all coal fired capacity was replaced by CCGTs (assuming efficiency of 50%).

d. Realistic forecast of gas demand in power generation, given estimated CCGT capacity that could be built in the short term (assuming efficiency of 50%).

2.30 It may be appropriate for Governments to indicate their commitment to higher environmental standards by imposing additional taxes on the fuels which contribute most towards atmospheric (and other forms of) pollution, or by mandating higher standards of environmental protection at new industrial and power plant, and probably at existing facilities as well. This would have the benefit of increasing the value of natural gas in the market (on the basis of gas being valued at its "opportunity cost") and therefore making it economically viable to build new pipelines and to obtain gas imports from higher cost areas.

G. Prospects for Increased Indigenous Gas Production

2.31 Romania, Hungary and Poland have significant indigenous gas production while Bulgaria, Czechoslovakia and Yugoslavia produce only small amounts. Total reserves in Eastern Europe (proven and probable) have been estimated at some 500 BCM and currently some 45 BCM of gas are produced annually, compared with annual imports of 45 BCM. Production facilities and transportation systems are in most cases in need of repair and upgrading, and underground storage capacity needs to be increased in order to meet winter demand peaks.

2.32 Although gas reserves are very modest if measured on a world scale, there are several areas in Eastern Europe with good potential for new discoveries which, if commercially viable, could help reduce dependence on energy imports and thereby improve prospects of a faster

economic recovery. However, Western capital will be an essential requirement for all exploratory activity.

2.33 Bulgaria, in general, and the Black Sea are viewed as having the best prospects. Exploration activities are being carried out in the Bulgarian, Romanian, and Soviet sectors of the Black Sea. Other areas with recognized potential include southeast Poland (particularly from coal-bed methane) and parts of Yugoslavia. Given that foreign investors can be attracted to explore for petroleum in these areas, and to provide the capital necessary to improve recovery on existing fields by replacing outdated and inefficient equipment, it seems likely that at least part of future demand increases could be covered by increased domestic production levels.

2.34 It is not possible to forecast future production levels without a detailed geological survey of each prospective basin, and an assessment of likely exploration and production costs. Based on US experience, we anticipate that it will be possible to at least maintain, and probably slightly increase, indigenous production in most countries. If the initial promise of substantial reserves of coal-bed methane in Poland can be fulfilled, then indigenous production could rise significantly.

H. Consumer Energy Pricing Policies

2.35 The price of energy relative to other goods has traditionally been low in most East European countries. Unlike Western Europe, residential prices were often substantially lower than those paid by the industrial and power generating sectors. Market reforms have tended to raise the price of energy faster than the rate of general inflation. This trend has been strengthened by the move to hard currency trading for imports from the Soviet Union.

2.36 Several countries are now increasing their efforts to move towards a market economy by liberalizing prices, with huge relative price increases as a consequence. In September 1991, Romanian gasoline prices were reported to have been raised to world market levels. Household electricity prices in Czechoslovakia were increased by 70 per cent on October 1, 1991. Czechoslovakia's Federal Economic Council has decided that prices shall be liberalized gradually until they reflect market forces. In Hungary, energy prices have doubled as the government has cut subsidies. Price reform is an essential step, and should be used to avoid misallocation of resources and giving the wrong incentives to both users and producers. The liberalization of prices is a necessary exercise on the way to full market economy, though a painful experience with price inflation and reduced living standards among its consequences.

2.37 Price liberalization is now well underway in most East European countries, a fact which makes analysis of historical prices relatively meaningless. In the country sections of the Appendix, we have indicated the more recent gas prices which have been made available to us (not for all countries). It should be noted, however, that these may have changed substantially since they were recorded.

I. From Comecon to Hard Currency

2.38 Since January 1991, trade between the Soviet Union and the former members of the Council for Mutual Economic Aid (CMEA) has formally been settled in hard currency based on world market prices. Though this policy has been implemented on paper, it appears not to have been fully activated immediately. Payment in kind is still far more common than hard currency cash payments. Neither the Soviet Union nor East European countries are likely to be prepared for the dislocations that could occur if this policy were put into practice. Three such potential consequences of this transition are:

a) A rapid increase in the prices of goods and services imported by Eastern Europe from the Soviet Union, and subsequently, a large potential outflow of hard currency reserves. It is estimated that Poland alone would be forced to pay an additional $1.2-1.5 billion per year if an immediate move to market pricing was enforced. Just one of many commodities - oil - is sold to Poland, at the equivalent of about $21/tonnes while the international market is trading similar quality oil for about $125/tonnes.

b) A virtual cessation in trade between CMEA countries and the Soviet Union because the East European countries do not have large hard currency reserves with which to pay for imports at market prices.

c) A competitive disadvantage for the Soviet Union if the six East European countries were to form a trading block (as has been suggested) and sell essential parts, components (some of which are not produced outside the CMEA countries) and technical assistance, on which the Soviet Union relies, at higher prices.

2.39 Oil export reductions have affected, and will continue to affect, Eastern Europe since the Soviet Union has cut back deliveries by about 30 per cent due to lower production and the necessity to trade with the West. Furthermore, the East European countries have lost the ability to re-export Soviet oil deliveries from which they previously earned significant amounts of foreign currency. Hence, a dual effect is felt: Eastern Europe will import less oil and, in addition, not be able to generate hard currency from re-exports. Obviously, alternative oil supplies are available, but it is questionable whether Eastern Europe has the ability to pay for imports without 'special' financing arrangements.

2.40 With gas, although prices have increased, and will continue to increase to market levels, the Soviet Union will still need to pay transit fees for using the pipelines located in Eastern Europe to make deliveries to Western Europe. The reality of this situation suggests that the pipeline owner (i.e. the East European countries) should be recovering transit fees to cover operation and maintenance costs and provide a return on capital invested in the pipeline. Major questions of rent sharing between the Soviet Union and East European countries arise, as pipelines are an essential link to major West European markets.

Table 2.5: The Gas Import Bill of Eastern Europe

	1989 Imports[a] BCM	1989 "Soft" Currency Cost $ Billion	1989 Hard Currency Cost $ Billion	Hard Currency Cost as % of 1989 GDP[b]
Bulgaria	6.1	0.3	0.6	1.1
CSFR	11.9	0.5	1.2	1.6
Hungary	5.9	0.3	0.6	1.6
Poland	7.9	0.3	0.8	0.8
Romania	7.4	0.3	0.8	1.5
Yugoslavia	5.4	0.4	0.6	0.4
Total	44.6	3.8	4.7	1.1

Source: Arthur D. Little
a. From the Soviet Union
b. Approximation, adjusted for inflation

2.41 A comparison of Soviet ruble gas exports to the CMEA six in 1989 with their potential value under hard currency trading at world market prices suggests that the higher price impact on Eastern Europe will be tremendous. The shock has already been seen in 1991 as shortages of all energy supplies have occurred due to a lack of hard currency with which to make purchases. In the future, Eastern Europe is likely to require large loans from the West to pay for energy imports, or a reversion to previous trading practices with the Soviet Union or its constituent republics.

2.42 Soviet natural gas exports to Eastern Europe, which in 1989 totaled 44.6 BCM, cost an estimated $2.0 billion under CMEA trading arrangements at an average price $45.69/1000 m3 ($1.21/MMBtu, at a "realistic" ruble exchange rate of 0.49 $/R. The official exchange rate is 1.589 $/R). With the present hard currency gas price of $2.75/MMBtu or $104.27/1000 m3 the same imports would cost $4.7 billion. Further moves to market-based pricing are likely to have very serious impacts not only on national accounts and trade balances between the former CMEA countries and the Soviet Union, but also on the supply and demand for gas within the region.

III. Future Gas Demand and Supply

3.1 In this section, we compare the projected gas demand, in the forthcoming two decades, of both Eastern and Western Europe with the gas we believe could be made available from new and existing supply sources at various points in time. We will begin by reviewing our demand projections for Eastern Europe as a whole. The bases and assumptions used for our demand forecasts are described in detail in the Appendix. Subsequently, we will describe currently planned expansion of infrastructure in Eastern Europe, and evaluate whether planned transport capacities will suffice to deliver supplies satisfying projected increases in demand. We will then go on to review current and future availability of gas from various supply sources, and the perceived relative supply security of individual suppliers.

3.2 We have calculated the costs of gas delivered to a border or landing point which would be most conveniently located for deliveries to the East European markets. Delivered costs have been calculated from six potential supply sources along ten alternative international transport routes.

3.3 In the final section, we will combine our conclusions reached in previous parts of the chapter, and discuss their implications. The purpose of this exercise will be to indicate:

- The volumes of gas which could realistically be made available to East European markets from import sources.
- The degree of competition for new gas between the markets of Eastern and Western Europe and its likely effect on international gas prices.
- The minimum price which would have to be paid in order to ensure that new projects are developed and brought on stream in time to meet future gas requirements.
- The possible cost advantages which could be gained from international cooperation.

3.4 Clearly, there is a complex set of relationships which exist between gas supply, demand and price. There is also an important set of relationships between gas supply, price and production and transmission costs.

3.5 Higher prices are likely to cause producers to make available greater quantities of supply, but to constrain demand. Low prices have the reverse effect. Short run price effects can be minor, for example in the residential sector, for which the price elasticity of demand is low, or can be major, for example in the industrial sector. A small change in gas prices can have a major effect on gas demand, depending on the relationship between oil prices and gas prices, and the extent to which consumers can switch between the two fuels at short notice.

3.6 In general, the principle of border price being equivalent with, or close to, long-run marginal costs can be observed in the gas industry in Western Europe. However, it is not easy to define with precision at what level long-run marginal costs are at any point in time, as this depends on what is meant by "long-run" (2 years, 5 years, 10 years ?), and what discount rate is used by investors. These relationships are extremely complex in practical terms.

A. Future Gas Demand in Eastern Europe

3.7 We have constructed three demand scenarios for each country, of which the base case represents our "best estimate" given current plans and economic outlook, and the high and low cases indicate the range of uncertainty surrounding the forecast. In our base case scenario, we project that overall demand in Eastern Europe initially will decline, returning to its 1990 level of 80 BCM in 1995. The initial decline in demand is assumed to take place in the industrial sector, being due to a combination of factors such as closure of noncompetitive and/or environmentally hazardous industries, increased energy conservation and initial end-use efficiency improvements. The decline in industry will be somewhat offset by growing demand in the residential/commercial and power generation sectors.

3.8 Thereafter, demand will grow by 2.8 per cent per annum during the 1995-2000 period and 3.6 per cent per annum during the 2000-2010 period. Over the long term, the power generation and industrial sectors will account for the largest absolute share of gas demand growth while the residential and commercial sectors will have the largest percentage increase in demand.

3.9 In our low scenario, we have assumed a continued slow to stagnating economic growth until 2000, with real economic growth and improvement of living standards not taking off until after the turn of the century. The low scenario also assumes little improvement in energy end-use efficiency and limited replacement of coal fired capacity.

3.10 Our high scenario, by contrast, assumes strong economic recovery from the mid 1990s and onwards, improvements in end-use efficiency and some replacement of coal-fired capacity by gas. No case assumes additional development of nuclear capacity.

3.11 The total demand of the six East European countries will amount to between 79 and 81 BCM in 1995, 86 and 102 BCM by 2000 and 110 and 173 BCM by 2010. Given present prospects for future indigenous production levels and continuation of presently contracted deliveries from the Soviet Union, this implies a supply gap of between 3 and 5 BCM by 1995, 43 to 79 BCM by 2005 and 53 to 117 BCM by 2010.

Table 3.1: East European Gas Demand Forecast

BCM	1990	1995	2000	2005	2010	Average Growth %
Low Scenario	80.7	79.0	86.4	97.3	109.5	1.5
Base Case	80.7	79.7	91.5	109.6	131.0	2.5
High Scenario	80.7	81.0	102.0	133.0	172.8	3.9

3.12 Of the countries studied, we believe that Yugoslavia (given present energy policies) will experience the largest growth in gas demand, followed by Poland and Czechoslovakia.

Table 3.2: East European Gas Demand Forecasts by Country

BCM	1990	1995	2000	2005	2010	Average Growth %
Bulgaria	6.5	6.6	7.1	7.4	7.7	0.9
Czechoslovakia	12.7	13.7	16.8	20.8	26.0	3.6
Hungary	11.3	11.6	12.7	16.1	19.4	2.7
Poland	10.1	11.1	13.5	16.7	21.2	3.8
Romania	33.2	30.5	33.2	36.7	41.1	1.1
Yugoslavia	6.9	6.2	8.3	11.9	15.5	4.1
Total	**80.7**	**79.7**	**91.6**	**109.6**	**130.9**	**2.5**

B. Planned Expansion of Infrastructure

3.13 If plans for increased consumption of gas in Eastern Europe are to be realized, gas transportation infrastructure will have to be extended significantly to allow for increased supplies of imported gas. Thus, several new pipelines leading into the area are being planned, including one from the Soviet Union to the Polish border, one from the North Sea via Denmark to Poland and one from Iran, which would lead across Turkey and deliver gas to the Balkan countries. In addition, a link is planned between the Yugoslav and Italian networks, through which Algerian gas is to be imported into Yugoslavia.

3.14 Other projects include interregional pipeline connections, mainly intended to link up the systems of the countries closest to the Soviet border with those further away, in order to improve the capability to import Soviet gas. Also being considered is the construction of an LNG terminal near Rijeka or Krk, which could supply not only Yugoslavia but also Hungary, Austria and Czechoslovakia with Algerian gas. These projects are described in more detail in Section C below. However, it is far from certain whether all these plans will be realized within the time frames considered, as most East European countries suffer from a severe shortage of financial resources. Western technology and financing may therefore be required.

3.15 *Conclusions.* Given our forecasts of energy demand, Eastern Europe will need additional supplies of between 30 and 50 BCM in 2000, growing to between 50 and 120 BCM in 2010. We expect part of these requirements to be met by increased indigenous production of gas from upgraded existing or yet-to-be found new gas fields. Existing pipelines are estimated to have a spare capacity of between 10 and 15 BCM per annum. Present plans foresee new pipelines to the area and LNG facilities adding a total transport capacity of around 40 BCM (including the Iranian pipeline to the Bulgarian border). If all new demand is to be met by imports, additional transportation capacity of 35 BCM and 105 BCM will be needed in 2000 and 2010, respectively (excluding presently planned capacity additions). Unless significant new indigenous resources are found, it seems clear that if gas demand is to be allowed to grow as foreseen in national energy plans, substantial new investments will have to be made in transportation infrastructure to the area.

3.16 It is not possible to estimate the total amount of investment which will be required without knowing which of these projects will proceed. Not all of them will go ahead. The total broad cost levels associated with the infrastructure are shown in Table 3.3 (to an accuracy of ±30%).

3.17 It will be a major challenge to mobilize the necessary investment in order to allow such projects to go ahead. At a time when the West European gas industry appears to require investment commitments of approximately $200 to $300 billion over the next 10 years or so, and the

worldwide oil refining and oil transportation industries need to make huge investments in environmental protection, there would appear to be a probability that the funds cannot be obtained to allow the gas industry to realize its full potential.

Table 3.3: Investment in Infrastructure

Project	Approximate Cost $m
LNG terminal in Yugoslavia	600
- associated pipelines	200
Pipeline from USSR	13300
Pipeline from Iran	7400
Pipeline from Norway (Troll)	5500
LNG ships (per vessel)	250

C. Short Term and Long Term Gas Availability

3.18 *USSR.* Currently, the Soviet Union is exporting annually some 60 BCM to Western Europe and some 45 BCM to East European buyers. An increase in deliveries from Western Siberia would require expansion of the production facilities in West Siberia, or development of the Yamal area, both of which hold sufficient additional reserves that could be produced at relatively low production cost (the huge field sizes result in very low unit production costs). New pipelines would however have to be built, as the spare capacity of the existing system at present is only about 10-15 BCM per annum.

3.19 Substantial volumes could also be released for exports if the efficiency in gas utilization within the Soviet Union was improved or transmission losses in the existing transportation system were minimized by upgrading/refurbishment of pipelines and compressors. All these measures would, however, require large sums of capital investment, which may be difficult to raise in the short term, though we understand Snam has reached agreement with Gazprom to undertake compressor and pipeline refurbishment.

3.20 We have calculated indicative capital investment required for 5 pipeline projects and 1 LNG project, which are given in the table below. We estimate typical project lead time to debottleneck existing facilities, from the time a decision has been made and financing has been arranged to first deliveries, to be around two to three years. A new pipeline from Yamburg could technically be built within five years, whereas the lead time of a development of the Barents Sea reserves is estimated at 10-12 years.

3.21 *Norway.* Currently, Norway is supplying some 27 BCM of gas (per annum) to Western Europe. In order to supply Eastern Europe, the existing pipeline network in Germany would have to be extended eastward, as for example is now occurring with Wintershall's Midal/Stegal system and parallel developments by Ruhrgas and VNG. Alternatively, a new offshore pipeline could be built, for example, via Denmark to the Polish coast, and then south to Czechoslovakia and Hungary.

3.22 In order to increase its ability to supply substantial new volumes to Europe, Norway would have to develop large new reserves such as Sleipner West or the Haltenbanken fields. However, Sleipner West gas has a high carbon dioxide content, making it difficult and costly to develop, and the location of the Haltenbanken fields off northern Norway would lead to a very high cost of gas delivered to the European coast.

Table 3.4: Indicative Capital Investment Required to Increase Export Capacity of the Soviet Union (New Pipelines/LNG; Excluding Production)

Supply Options	Volume BCM	Investment $ billion
West Siberia to Polish border (Brest-Litovsk)	5	13.3
- Polish border to Warsaw	(5)	+0.4
West Siberia to Uzhgorod	35	14.2
- Uzhgorod to Prague	(10)	+1.0
- Uzhgorod to Warsaw	(5)	+0.4
- Uzhgorod to Budapest	(5)	+0.4
West Siberia to Romanian border (Ismail)	5	10.2
- Romanian border to Bucharest	(2.5)	+0.1
- Romanian border to Sofia	(2.5)	+0.1
Barents Sea LNG to Poland (including liquefaction and regasification)	(11)	5.8[b]
Barents Sea pipeline gas to Poland (Brest-Litovsk)	15	5.2
TOTAL USSR	60[a]	51

a. Figures in the bracket not included in total since they would not increase marginal deliverability (it is unlikely, for example, that both a Barents Sea LNG project and a pipeline from this area would be realized).
b. Including cost of ships.

3.23 The North Sea fields which are being developed, or considered for development at present, are all relatively small, and will probably, to a large extent, be used to substitute the now postponed initial volumes from Sleipner East. Gas from the Troll Phase 1 development is, given presently planned production and transport capacities, already committed to Western buyers under the Troll Agreement (i.e. if all options are taken into account). It seems likely that more gas will be found in the Norwegian part of the North Sea when exploration activities in this area are restarted, but until such time possibilities to expand production significantly beyond the above mentioned projects seems limited.

3.24 Based on past experience, we estimate Norwegian North Sea gas projects to have technical lead times of up to 8 years, while Haltenbanken reserves would take up to 10 years, and Troms gas (located off the northernmost coast of Norway, including, for example, the Snohvit field) up to 12 years to develop.

3.25 *Algeria.* Algeria, already linked to Western Europe via the Transmed pipeline to Italy and exporting LNG to several West European buyers, has substantial reserves of gas. Proven reserves in 1990 amounted to 3,750 BCM, to which up to 1,250 BCM could potentially be added. The current production rate is close to 100 BCM a year of which about 50 per cent is reinjected after LPG extraction. Some 30 BCM are currently committed for export to West European buyers (growing to 40 BCM in 2000). We are not aware of plans to increase gross or net production at the main gas field, Hassi R'Mel, before the late 1990s. We believe however that a further 5 BCM per annum could be made available immediately for 20 years without damaging ultimate recovery.

Table 3.5: Indicative Capital Investment Required to Increase Norwegian Export Capacity (New Pipelines/LNG; Excluding Production)

Supply Options	Volume BCM	Investment $ billion
Via Emden to CSFR border	10	5.5
- CSFR border to Prague	(5)	+0.1
- Prague to Budapest	(5)	+0.1
- CSFR border to Polish border	(5)	+0.1
- Polish border to Warsaw	(5)	+0.5
Via Denmark to Poland (Niechorze)	10	4.5
- Niechorze to Warsaw	(5)	+0.3
- Niechorze to Prague	(5)	+0.4
- Niechorze to Budapest	(5)	+0.5
Norwegian LNG to Poland (including liquefaction and regasification)	5.5	2.7[a]
Total Norway	25.5	14.7

a. Including cost of ships

3.26 The current gross capacity of Hassi R'Mel exceeds 100 BCM per annum. Production was 86 BCM in 1989, approximately 90 BCM in 1990, of which up to 60 per cent was reinjected. Reinjection is unlikely to fall below 50 per cent before 2000, leading to a net output of 50 BCM per annum, unless Sonatrach's views on reinjection change.

3.27 Production will, however, increase - developments in the Amenas/Rhourde Nouss/Gassi Touil areas over the 1990s will add approximately 14 BCM per annum to total production capacity. These volumes could potentially be made available by 1995, but are more likely to come on stream after 1996.

3.28 Given current export commitments, Sonatrach is left with a deficit of 6 BCM by 1995 and 15 BCM by 2000, depending on deliveries to the USA, which are flexible under the Panhandle contract, and the timing of the Shell contract. Further investments in more capacity to increase production are therefore required.

3.29 Existing pipelines leading from Hassi R'Mel to Arzew, where a potential new LNG plant would presumably be located, have spare capacity of around 40 BCM. There is around 9 BCM of "spare" nameplate liquefaction capacity. Contracts have recently been let for refurbishment of existing plants to allow for a return to nameplate capacity. We believe Sonatrach is about to let further contracts to increase annual production capacity by a further 6.5 BCM. Refurbishment lead time is estimated at 3 years.

3.30 In order to expand Transmed, new sub-sea lines would have to be built. It has now been decided to build an additional line across the Mediterranean (extending the theoretical capacity from approximately 7 BCM to approximately 21 BCM per annum), primarily to serve Italy, but also to supply small volumes to Yugoslavia. Current commitments in Transmed amount to 20.2 BCM, but the line will be considered fully utilized even after the expansion, as 4 BCM of reserve capacity is required for reasons of supply security. Accordingly, we believe a second new subsea line is about to be announced with the possibility of a third. Transmed expansion projects are estimated to have a technical lead time of two years.

Table 3.6: Indicative Capital Investment Required to Increase Algerian Export Capacity (New Pipelines/LNG; Excluding Production)

Supply Options	Volume BCM	Investment $ billion
Via Transmed to Monfalcone	5	3.1
- To Belgrade	(5)	+0.9
- To Prague	(5)	+1.0
- To Budapest	(5)	+0.4
- To Bucharest	(2.5)	+1.1
LNG to Omisalj	5.5	2.4[1]
- To Belgrade	(5)	+0.9
- To Prague	(5)	+1.3
- To Budapest	(5)	+0.5
- To Bucharest	(2.5)	+1.2
Total Algeria	10.5	12.8

a. Including cost of ships

3.31 The Algerian supplier Sonatrach, together with Morocco's SNPP and Enagas of Spain, is proceeding with plans to build a pipeline from Hassi R'Mel to Spain via the Straits of Gibraltar. The purpose of Phase I of the project is to supply Morocco and Spain, but a subsequent phase envisages selling gas to France and Germany via this pipeline. Accordingly, Algerian production capacity may need to be expanded in the late 1990s, and almost certainly post 2000. However, this seems unlikely to cause a large increase in production costs, though this may depend in part on the location of future exploratory efforts.

3.32 At present, Algeria does not supply gas to Eastern Europe. A contract is likely to commence in the early 1990s, for 0.6 BCM per annum to be delivered via the TransMed line to INA of Yugoslavia, with the possibility of expansion to 2 BCM later to other Yugoslavian buyers. Analysis of the costs of delivering Algerian gas to Eastern Europe, which is described in more detail elsewhere in this document, suggests that Algeria has a competitive advantage over other suppliers for deliveries to several Eastern European countries, especially Yugoslavia and Hungary.

3.33 *Libya.* Like Algeria, Libya has large gas reserves which are estimated to be in excess of 1,500 BCM. Proven reserves in 1990 amounted to 1,220 BCM, with an ultimate potential of 2,000-2,800 BCM. Libya is still relatively unexplored, with two thirds of the reserves in onshore areas.

3.34 The reserves are located primarily in the Sirte Basin in the south east of the country (holding 650 BCM). Other areas with hydrocarbon reserves are the Ghadames Basin (in the south west), with approximately 170 BCM, the Bouri Area (offshore) with around 70BCM, and the 7th November fields (300 BCM), located in an offshore development zone shared with Tunisia.

3.35 Libya has a theoretical potential to export 20 BCM per annum by 2000. The current production rate is around 14 BCM a year. Twenty per cent (2.8 BCM) of this is exported to Spain. This volume could easily be increased by further development. Technical lead times are similar to those of Algeria.

Table 3.7: Indicative Capital Investment Required to Increase Libyan Export Capacity (New Pipelines/LNG; Excluding Production)

Supply Option	Volume BCM	Investment $ billion
Libyan LNG to Omisalj	5.5	2.4[a]
- To Belgrade	(5)	+0.9
- To Prague	(5)	+1.3
- To Budapest	(5)	+0.5
- To Bucharest	(2.5)	+1.2
Total Libya	5.5	6.3

a. Including cost of ships

3.36 Past problems of foreign investors, discouraged by concerns over contractual stability and political aspects, have however so far severely hampered the pace of development. Contract disputes with Spain and Italy over gas prices have also contributed to a less than favorable reputation in terms of supply security. In addition, only the Barcelona and La Spezia LNG terminals have treatment facilities for Brega LNG, which contains higher hydrocarbons that must be separated from the gas before it can be fed into a transmission system. The Brega plant is now being revamped by the addition of an LNG extraction facility to permit a more standard quality of LNG to be exported.

3.37 *Qatar.* Qatar's vast gas resources are contained in the giant North Field, located in the waters offshore Qatar in the Persian Gulf. The North Field is an extension of Iran's South Pars field. Proven reserves are 4600 BCM, current production is 6.5 BCM per year. BP, Total and Qatar's national petroleum company (QGPC) and Japanese partners are planning the development of an LNG scheme based on deliveries from the North Field. The Japanese utility Chubu Electric has bought the planned output of the future plant; an annual 5.5 BCM of gas in the form of LNG.

3.38 We are not aware of an additional LNG project being considered at present, but would not rule out this possibility if willing buyers can be found. We have calculated the costs that would be involved, indicating the prices that East European buyers would have to offer in order to encourage further development of Qatar's export potential to European markets.

3.39 Given the long shipping distance to Japan, and the relatively small volumes planned to be exported under the present agreement, the planned LNG harbor facilities are unlikely to be utilized to full capacity. If additional LNG trains were to be built, harbor facilities could presumably be extended at moderate cost to accommodate increased shipping volumes, or even used as they are.

Table 3.8: Indicative Capital Investment Required to Increase Qatar's Export Capacity (New Pipelines/LNG; Excluding Production)

Supply Option	Volume BCM	Investment $ billion
Qatar LNG to Omisalj	5.5	3.4[a]
To Belgrade	(5.5)	+0.9
To Prague	(5.5)	+1.3
To Budapest	(5.5)	+0.5
To Bucharest	(5.5)	+1.2
Total Qatar	5.5	7.4

a. Including costs of ships

3.40 *Iran.* Iran has proven reserves of gas of around 14,200 BCM, and is currently producing only 20 BCM per annum, largely consumed domestically. The country has tried to encourage Qatar to participate in joint further development of South Pars, and to share some of the costs involved. However, while Iran is planning to build a large pipeline (capacity 30 BCM or more) to Europe, of which approximately 20 BCM might be sold in Europe (the balance in Iran or Turkey), and further pipelines to Pakistan and India, Qatar wishes to concentrate on exporting LNG to the Far East.

3.41 Iran is developing the North Pars field at a cost of around $4.0 billion. Technically, the gas could be onstream in 1995. However, in order to make the European pipeline project economically viable, Iran has to find buyers for the full 20 BCM per annum to Europe, who are willing to pay the premium required to transport the gas to European markets. Iran also has to overcome its perceived image as a politically unstable source of supply. So far, Iranian gas has not been able to compete with alternative gas sources in supplying the markets of Western Europe, though it has had a contract to supply Bulgaria via exchange with the USSR (now canceled).

Table 3.9: Indicative Capital Investment Required to Increase Iranian Export Capacity (New Pipelines; Excluding Production)

Supply Options	Volume BCM	Investment $ billion
To Bulgarian border	20	7.4
To Sofia	(20)	0.4
To Belgrade	(18)	0.7
To Bucharest	(2.5)	0.2
Total Iran	20	8.7

3.42 *UK.* In the medium term (mid 1990s to 2000), we estimate that UK gas will be available at the UK beach at a cost of between $ 2.55/MMBtu or higher, as the remaining cheaper reserves will by then have been contracted. Assuming that the cost delivered at the beach of Continental Europe would be the same, the delivered cost at, for example, the Czechoslovakian border would lie in the vicinity of $ 3.20/MMBtu, or more. Although the UK would thus be able to compete with Norway in cost terms, the price obtainable in the gas hungry UK market would be considerably higher, even if end consumer market values were the same. Thus, unless East European buyers are prepared to pay premia of $0.75/MMBtu or higher, no UK producer can be

expected to be willing to export to Eastern Europe as long as there is unsatisfied demand in the UK.

3.43 ***The Netherlands.*** The Netherlands are facing a similar situation to the UK. There are too many potential western gas buyers capable of outbidding East European competitors on the way from the Netherlands to the borders of Eastern Europe to make it realistic for the limited amounts of additional Dutch gas that will be released for export in the next two decades ever to reach these markets, unless an existing buyer, such as Ruhrgas, is willing to release some of its portfolio to another country, perhaps in the form of a joint venture (as has occurred in the former GDR).

3.44 ***Conclusion.*** In conclusion, from an availability point of view, the most likely alternative supplier to the Soviet Union in the short to medium term seems to be Algeria. In the medium to long term, Iran, Libya and Qatar could be regarded as potential additional sources. In the case of Norway, we find it more difficult to predict substantial short to medium term future exports to Eastern Europe, as it is unlikely that sufficient volumes can be made available at a price which is acceptable to buyers and which adequately covers the investment required on the part of the producers.

D. Supply Security

3.45 Security of supply is a relative term which is used to express the extent to which the risk of default connected with gas deliveries to a certain market or customer can be minimized.

3.46 The degree of supply security in a gas market depends on:

- The long-run availability and accessibility of sufficient gas volumes to cover expected growth in demand (long-term supply security); and
- The degree to which the risk of involuntary supply interruption due to, for example, a temporary inability of individual producers to deliver according to contract can be minimized, e.g. through diversification (short-term supply security).

3.47 In this context, it may also be worth describing the two different types of short-term supply security between which we usually distinguish, i.e. a technical and commercial supply security, where the former refers to likelihood of interruption of gas production due to technical reasons, and the latter to other non-technical causes of supply interruption, such as breach of contract due to price disputes etc.

3.48 Eastern Europe has up to now relied on the Soviet Union for a large part of its energy needs. In recent years, both oil and gas supplies to Eastern Europe have been constrained due to production problems within the Soviet Union. Field production problems associated with poor labor relations, non-availability of spare parts, severe weather, etc., and gas transportation difficulties caused by pipeline ruptures, leaks, etc. have sometimes meant that supplies have been curtailed. West European buyers are believed not to have suffered curtailments to the same extent as East European buyers in the past, perhaps because of the more attractive prices which were paid by Western buyers until recently.

3.49 The supply difficulties of the Soviet Union seem likely to deteriorate further. The current political instability seems certain to disrupt the availability of spare parts and to interfere with production and maintenance operations. The fragmentation of the USSR into its constituent republics, and the possible disintegration of some of the republics themselves, suggests that the supply problems will not be resolved quickly by internal action, an instability which prevents external partners from negotiating suitable arrangements to allow them to assist in resolving supply

problems. Accordingly, dependence on the USSR for gas supply becomes more risky (from a purely technical point of view) as time progresses, until political stability returns.

3.50 After decades of political and economic dependence, the East European countries now wish to diversify away from the Soviet Union as single source for imported gas. This diversification is an attempt to ensure that the gas volumes needed to satisfy demand are delivered as specified.

3.51 Supply diversification is effectively an insurance policy, assuming that new suppliers are equally or more secure. In order to secure their own ability to supply consumers with gas and minimize vulnerability to supplies being interrupted (for example as a result of temporary production shut downs), gas importers build up gas supply portfolios, consisting of contracts with several suppliers, possibly backed up by strategic storage.

3.52 Different suppliers are regarded as more or less secure in terms of the extent to which they can be relied upon to deliver gas according to contractual terms. Thus, the addition of an individual supplier can add more or less to the overall risk of a supply portfolio, depending on how "secure" he is.

3.53 In Table 3.10, we have evaluated all realistic potential suppliers to Eastern Europe according to aspects we perceive as important to supply security, and ranked them on the basis of total supply security (being the sum of the weighted average scores[1]). It should be noted that aspects and weightings chosen are based on our own perceptions of suppliers, and are therefore subjective. The weights have been chosen arbitrarily on the basis of our own evaluation of individual suppliers and their contract and production histories to date. In this context it is worth mentioning that historical evidence on Libya, Iran and Qatar does not exist, which serves to explain their high proportion of neutral "grades". This may obviously distort the overall evaluation somewhat.

3.54 ***Conclusions.*** As can be seen from Table 3.10, we would, on a long term basis, rank Algeria as the most secure supplier and the Soviet Union as the least secure supply source from the perspective of an East European buyer. Regardless of how critically individual alternative suppliers are viewed, it would be difficult to deny that some of the most fundamental current weaknesses of the Soviet Union collectively serve to undermine its perceived security of supply in relation to those of other sources. Thus, in order to increase overall security of supply, all of the alternative suppliers evaluated would represent possible candidates.

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1 In order to indicate order of supply security, we have used a common methodology for numerical analysis of qualitative information:

(i) Select relevant aspects of supply security on the basis of potential to influence future security as a supplier. For example, production history is a very relevant indicator (i.e. past occurrences of interrupted gas flow due to technical reasons, etc....). Gas quality, which also varies between supply sources, would not necessarily be relevant, unless there is risk of displacement of interrupted volumes by different quality gas.

(ii) Weight aspects in order of importance (based on subjective perceptions).

(iii) Evaluate each supplier against aspects and "grade" them:+1 if their performance contributes positively to supply security, -1 if it serves to reduce supply security, and 0 if their performance has a neutral effect on supply security.

(iv) Multiply "grades" by weights.

(v) Divide sum of scores for individual suppliers by the sum of weights to obtain overall supply security ranking.

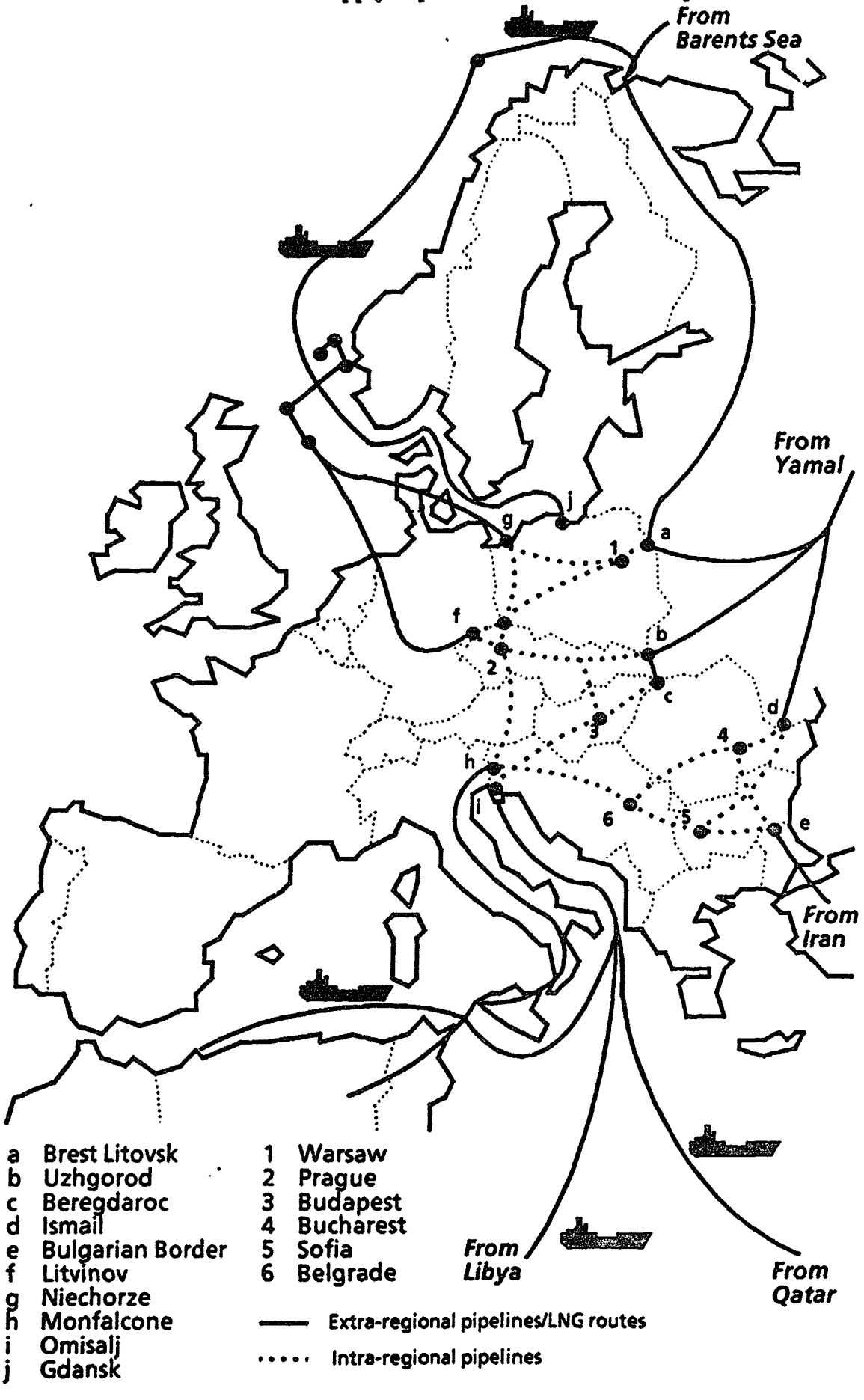
3.55 Diversification of supply sources spreads the risk of unplanned gas shortages to several suppliers, thereby reducing total risk and increasing security of supply. Like an insurance policy, it carries a premium in the form of higher cost per cubic meter of gas purchased. The larger the number of additional suppliers, the greater the cost per unit of gas imported is likely to be. The reason for that is a combination of the smaller volumes that would be purchased from each supplier and the large differences in production and transportation costs between different sources.

Table 3.10: Comparison of Soviet Security of Supply with other Potential Suppliers

Aspects of Supply Security[a]	USSR	Norway	Algeria	Libya	Iran	Qatar	Weight
Size of reserves	+	0	+	0	+	+	5
R/P ratio	+	+	+	+	+	+	5
Own consumption in relation to exports	-	+	+	0	0	0	4
Distance to market	-	0	+	+	-	-	4
Capacity utilization							
- Production	-	+	+	0	0	0	5
- Transportation	-	-	0	0	0	0	5
Contract history	+	+	-	0	0	0	5
Production history	+	0	+	0	0	0	4
Deliverability	0	+	+	0	0	0	5
Political stability	-	+	0	0	-	+	3
Risk of national disintegration	-	+	+	+	+	+	3
Risk of structural change (industry	-	0	+	+	+	+	2
Risk of political intervention	-	+	-	-	-	0	3
Need for hard currency	+	-	+	+	0	-	5
Need for new investment in order to expand/ maintain exports	+	-	+	+	0	-	5
Ability to attract investment	-	+	+	-	+	+	3
Importance of Eastern Europe in export portfolio	+	0	0	0	+	-	3
Overall supply security ranking (weighted)	**6**	**2**	**1**	**3**	**4**	**5**	

a. Aspects weighted in order of importance: 5 = critical; 1 = of minor importance

Chart 3.1: Gas Supply Options for Eastern Europe



E. Supply Cost Calculations

3.56 We have calculated the supply costs and constructed supply cost curves for the individual countries of Eastern Europe as well as for the region as a whole. The supply cost curves of individual countries can be found in the country sections of the appendix. It may be worth noting that the costs calculated are not equivalent with gas prices, which would be determined in negotiation between buyer and seller.

3.57 The cost of delivering gas from six supply sources to 17 delivery points was calculated, resulting in 48 different supply options. The supply sources studied include the following:

USSR

- Incremental West Siberian gas volumes through existing network.
- Incremental volumes through a new 35 BCM pipeline from Yamal to Uzhgorod, from which smaller branches spur off to Brest-Litovsk and Ismail.
- Barents Sea gas, delivered via a new pipeline to Brest-Litovsk or to an assumed new LNG terminal in Gdansk (due to an assumed very long development time of a potential Barents Sea project and the high costs that would be associated with it only costs delivered Gdansk have been calculated for this option).
- Supply cost estimates are based on Western standard cost assumptions.

Iran

- 20 BCM of gas delivered to Eastern Europe from northern Iran via the planned new pipeline through Turkey (with another 10 BCM consumed in Turkey), delivered at the Bulgarian border.

Norway

- North Sea gas delivered via Emden and Midal/Stegal to Litvinov in Czechoslovakia.
- North Sea gas delivered via Denmark and the proposed Polpipe line to Niechorze in Poland.
- LNG from the Snohvit field off the north Norwegian coast delivered to an assumed new LNG terminal in Gdansk (due to an assumed very long development time of a potential Snohvit LNG project and the high costs that would be associated with it only costs delivered Gdansk have been calculated for this option).

Algeria

- Pipeline gas delivered via Transmed through Italy to Monfalcone on the Yugoslavian border.
- LNG produced at a new plant and delivered to a proposed terminal in northern Yugoslavia.

Other

- Libyan LNG produced at a new plant and delivered to a proposed terminal in northern Yugoslavia.

- Qatar LNG produced at a new plant and delivered to a proposed terminal in northern Yugoslavia.

3.58 Although the United Kingdom and the Netherlands could be in theory be regarded as potential suppliers to Eastern Europe, we have decided not to include them in this review of potential new suppliers. If our expectations concerning a developing supply deficit in the UK market in the forthcoming two decades are correct, a potential UK exporter will base his decision on whether to export or not on the highest margin he can receive on delivered gas. Against that background, gas exports from the UK to Eastern Europe seem highly unlikely to us.

3.59 Nigerian LNG has also been left aside, as previous calculations have indicated that Nigerian LNG delivered Europe would be significantly more costly than Qatar LNG, which is one of the most expensive supply sources investigated. Nigerian LNG is more costly mainly due to higher production costs, gas gathering costs and larger need for new infrastructure (greenfield site).

3.60 ***Cost Assumptions.*** To arrive at realistic estimates of investment and operating costs, various assumptions had to be made concerning pipeline diameters, routing (topographic and climatic considerations), compressor station spacing, steel quality, roughness of pipe, etc. The degree of accuracy of our estimates is assessed at approximately +/- 30 per cent.

3.61 A number of further simplifying assumptions have been made:

- No allowance was made for the fact that full economies of scale would probably not accrue to individual buyers. Instead, volumes and costs reflect the size of pipelines at the point of delivery.

- We have looked at the delivered cost of individual suppliers at several delivery points, although the implication of this is that aggregated gas volumes can be misleading in terms of their ability to indicate the maximum quantity of gas available from any individual source.

- Production cost estimates are resource cost based, reflecting investment costs, field operating expenses and production volumes discounted over project life (of field, at 10 per cent discount rate). Taxes have not been included.

  Transport, liquefaction and regasification costs include capital and operating costs, calculated on the basis of the following assumptions:

- 20 year economic life for pipeline projects (typical duration of supply contract).

- 25 year economic life for LNG tankers (standard estimate of ship builders, although in practice, LNG tankers will have longer life if properly maintained).

- 10 per cent real discount rates, costs expressed in 1991 terms. A 10 per cent discount rate could be regarded as relatively low, individual project risk and opportunity cost of capital may require higher rates. Higher discount rates would result in higher costs.

- 8000 hour load factor (91 per cent). In the interest of consistency and comparability, we have chosen not to differentiate load factors on individual transport options calculated. A load factor of 91 per cent would be a standard assumption for long distance, onshore pipelines. In some circumstances, it could be considered as a high assumption, e.g. for pipelines directly connected to a single offshore production source. Lower load factors would result in higher costs per cubic meter.

- Instantaneous loading to full capacity is an important simplification. Normally, immediate utilization of the maximum capacity of a new pipeline would only occur at construction of small pipelines. For larger pipelines, capacity is usually built up in stages. However, in order to take this into account in our calculation, we would have had to make further assumptions on capacity and investment build-up. A gradual build-up of capacity would have had an increasing effect on transport costs per cubic meter, while a gradual build-up of investment would reduce them. The additional degree of uncertainty and complexity introduced by taking this into account would, in this context, of primarily aiming to indicate transport costs in order of magnitude, not have corresponded to the value added of increased accuracy.

F. Supply Cost Curves

3.62 Of all supply options studied, incremental gas volumes from the USSR delivered through the existing system would be the cheapest (in cost terms). This is because marginal costs of transportation would be limited to additional compressor fuel use (3 per cent of throughput), and marginal costs of production are likely to be very low ($3.80- $18.95/1000 m3 or $0.10 - $0.50/MMBtu). At present, there is only about 10-15 BCM per annum of spare capacity available from the Soviet Union. Beyond that, new production capacity must be developed and additional pipelines built.

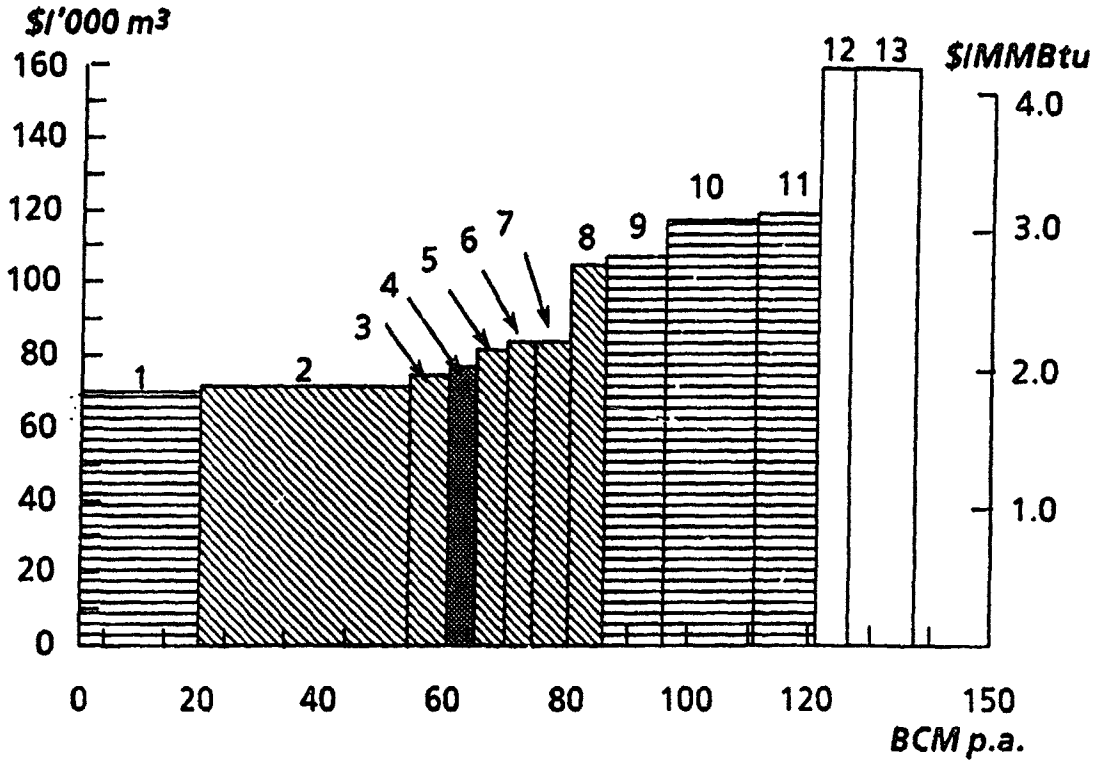
3.63 In order to diversify their supply, East European gas buyers could approach a number of different potential sources. In the short term (within 5 years) however, only North-African LNG, Qatar LNG, or Algerian pipeline gas are likely to be available. Other sources would take longer time to develop.

3.64 Of the non-Soviet sources, North African gas (both LNG and pipeline gas) and Iranian gas are the least costly to deliver to the borders of Eastern Europe, though of course the situation for each individual country varies according to its location. Qatar LNG is more expensive than North African LNG due to the larger shipping distance. Norwegian North Sea gas delivered by pipeline to Europe would be the most costly to deliver (apart from USSR Barents Sea pipeline gas), and probably not be available before 2000. The Norwegian cost disadvantage is a result of the combination of high production costs and large distances from wellhead to market.

3.65 *Conclusions.* In the short to medium term (deliveries beginning before 2000), we believe that between 15 and 20 BCM could be made available to Eastern Europe, of which 5.5 BCM would be in the form of North African LNG delivered to a new terminal at Omisalj, an additional 5 BCM of Algerian pipeline gas delivered via the Transmed pipeline, and the rest consisting of Soviet volumes. The total investments required to bring these to the East European border would be approximately $5 billion. Additional supplies from other sources like Iran, new developments in the Soviet Union and Norway, or LNG from Qatar seem unlikely to be made available before 2000.

3.66 The Iranian gas pipeline project, which is presently being considered, would need a price (at the Bulgarian border) above $1.90/MMBtu ($70.85/1000 m3) in order to be economical (given full utilization). In order to provide incentives for new Norwegian North Sea gas projects to be developed, border gas prices of between $2.85 and 3.20 per MMBtu ($107.25 - $120/1000 m^3) would have to be offered.

Chart 3.2: Supply Cost Curve for Eastern Europe - Gas Delivered to Closest Border/Landing Point



Supply Options

1 Iranian gas at Bulgarian border
2 USSR gas at Uzhgorod
3 USSR gas at Beregdaroc
4 Algerian gas at Monfalcone
5 USSR gas at Ismail
6 USSR gas at Brest-Litovsk
7 North African LNG at Omisalj
8 Qatar LNG at Omisalj
9 Norway Polpipe
10 USSR (Barents Sea to Brest-Litovsk)
11 Norway via Emden
12 Norway LNG at Gdansk
13 USSR Barents Sea LNG at Gdansk

Deliveries from:

1994
1996
2000
2005

G. Future Gas Supply and Demand

3.67 The collapse of economic systems in Eastern Europe has ended a period of economic and social interdependence, which previously made trade with the Soviet Union a necessity. The transition to hard currency-based trade has provided a catalyst for East European countries to diversify away from Soviet gas supplies.

3.68 Indigenous gas production is unlikely to remain constant in the future without significant investment in exploration. Depletion of Eastern Europe's gas reserves occurred at a very rapid pace historically and production levels will not be maintained in the future unless significant additions to reserves are made. The latest data (for 1989) suggests that Eastern Europe is dependent on the Soviet Union for about 50 per cent of total gas requirements. However, considering Eastern Europe without Romania (the largest gas producer), dependence on Soviet gas rises to about 70 per cent. Whether or not this dependence increases in the future will depend on:

- The ability of the Soviet Union to offer competitive gas pricing contracts to Eastern Europe.
- The attractiveness of alternative gas supply sources such as Norway, Algeria, Iran and Qatar.
- How rapidly new infrastructure can be developed to augment alternative sources of natural gas.
- The ability of buyers to pay in hard currency.

3.69 The forecasts in this document are predicted on the basis of crude oil prices rising from approximately $25 per barrel (for Dubai crude f.o.b.) between 2000 and 2005, in 1991 dollars, and stabilizing at this level. Naturally, a smooth trend is not expected to occur in reality, as there will be a trading range of $3 or $4 around these levels. Consistent with this forecast of crude oil prices, we expect gas prices to rise from their current level of approximately $2.25-2.50/MMBtu (high load factor gas, delivered European border, adjusted for indexation time lags) to approximately $3.50-3.75/MMBtu. (The reason gas prices grow slightly more than crude oil prices is because the link between oil and gas prices is assumed to be via gas oil and low sulfur fuel oil, not crude oil, and therefore reflects developments in the oil refining industry, changing slate of crude oils - i.e. higher sulfur crudes, changing product demand, etc.).

3.70 Our high case forecast for Eastern Europe as a whole shows indigenous production declining from 37 BCM in 1990 to 14 BCM in 2010. This forecast presumes that production on existing fields continues to decline, with some marginal improvement of R/P ratios to reflect upgrading of production facilities. Imports will have to increase throughout the entire period from 44 BCM in 1990 to 90 BCM in 2000, increasing considerably to 159 BCM by 2010, as demand growth will exceed reserve additions. (The import requirements for the base case are somewhat lower, cfr. pg. iii). This would require investments in new infrastructure to the East European border of $20 billion up to 2000 (including new pipeline from West Siberia). In the longer term, additional investment of up to $50 billion may have to be made in order to bring in adequate amounts of additional supplies, unless substantial discoveries of indigenous reserves are made.

3.71 Competition for the volumes available to European buyers in future will be strong, as both East and West have substantial supply gaps to fill. The ability of individual importers to offer competitive market prices will depend on the value of gas in each market, distribution costs and distance from supply source.

Table 3.11: Projected European Gas Supply and Demand Balance (High Case) BCM

	1990	1995	2000	2005	2010
Western Europe					
Demand	*260*	*319*	*379*	*422*	*460*
Supply (Committed)					
Indigenous	121	145	125	100	75
Norway	28	27	35[a]	35[a]	35[a]
USSR	55	64	64	64	64
Algeria	28	38	40	40	40
Netherlands	28	40	40	40	40
Nigeria			5	5	5
Deficit	***0***	***5***	***70***	***139***	***191***
Eastern Europe:					
Demand	*81*	*80*	*102*	*133*	*173*
Supply (Committed)					
Indigenous	37	36	12	13	14
USSR	44	38	40	40	40
Algeria	0	2	2	2	2
Iran		3	3	3	3
Deficit	***0***	***0***	***45***	***75***	***114***
TOTAL DEFICIT	**0**	**5**	**115**	**214**	**315**

a. If all the Troll options are exercised, Norway would be selling 47 BCM from 2000 onwards

3.72 Obviously, as far as financial strength is concerned, East European buyers will initially, due to the fact that they are in the process of rebuilding their economies, have a disadvantage in relation to their West European neighbors. Distance from supply source affects transport cost and therefore the price required by the supplier. Eastern Europe has in these terms a competitive advantage vis-a-vis Western Europe when it comes to supplies from the Soviet Union, Iran, Libya and Qatar. As regards ability to offer higher prices however, it seems clear that Eastern Europe will have severe problems in competing with Western Europe for the incremental volumes available for supply to European buyers during the next decade. Even if gas market values were similar to those of Western Europe (which is a possibility, since substitute fuel prices will gradually move towards international market price levels), internal transmission and distribution costs are likely to be much higher than in Western Europe due to the substantial new infrastructure investments that will have to be made, and the lower volumes which are consumed, leading to lower prices.

3.73 Clearly, the volumes which will be made available for sale to buyers in Eastern Europe will depend on the prices offered to suppliers. In the end, suppliers are likely to be offered sufficiently high gas prices to provide incentives to develop more costly reserves in remote locations. However, as gas is in most of its applications 100 per cent substitutable by other fuels, gas prices could not rise above those of competing fuels (adjusted for any premium due to superior convenience, efficiency, environmental friendliness, lower operating or capital cost, etc.). Future

gas price developments will therefore ultimately depend not only on the supply and demand of natural gas, but also of other energy forms.

3.74 With rapidly-emerging potential supply deficits in both Western and Eastern Europe, "sellers market" conditions prevail. Gas companies in both areas will compete for the available supplies and there is likely to be an increase in prices at the European border as a consequence.

3.75 Precisely how the deficits are to be addressed is a matter for the gas companies themselves, acting jointly in consortia or individually. Each company is likely to wish to create a balanced portfolio of supplies, with a judicious blend of imported and indigenous availabilities, some low resource cost gas to balance the risks of high resource cost gas, and gas from "secure" supply sources to balance that obtained from "risky" supply sources. Each company is likely to prefer a unique combination of gas from the various potential sources, taking account of their market size and structure, energy prices, the degree of competition and other factors.

Appendices

Country Sections

Bulgaria

A. The Bulgarian Energy Industry - Summary

- Bulgaria's national primary energy fuel mix in 1989 consisted of 38 per cent coal, 37 per cent oil, 14 per cent natural gas and 11 per cent nuclear, hydro, and imported electricity (Source: IEA Energy Balances).
- Natural gas has been used since the 1960s, primarily in the industrial sector.
- Natural gas consumption has, since the early 1980's, grown at an average 6 percent per annum.
- The natural gas grid is not very well developed, primarily serving the purpose of bringing Soviet supplies into the country for further transport to industrial consumers and CHP plants.
- The main problems facing the government of Bulgaria in the energy sector are the following:
  - Limited domestic energy resources apart from low grade brown coal
  - Lack of financial resources necessary for investment in alternative power sources, and exploration for indigenous hydrocarbon reserves
  - Dependence on the Kozludoi nuclear power plant for supply of 25-30 per cent of national power demand
  - Dependence on the Soviet Union as single source supplier of oil, coal, imported electricity, uranium and gas (apart from contracted gas from Iran).

B. Historical Natural Gas Supply and Demand

Bulgaria has proven hydrocarbon reserves of about 2 million tonnes of oil and 13 BCM of natural gas. However, it is believed that additional unproved and highly prospective reserves are located in the Black Sea. Future exploration efforts are expected to be concentrated in this region.

Gas demand was 5.9 BCM in 1989, representing about 14 per cent of total energy demand, up from 9 per cent in 1980. A very small amount (less than 2 per cent) of gas is produced indigenously, while the remainder is imported from the Soviet Union. Gas discoveries in the Black Sea could increase future domestic production significantly.

In the absence of hard data, it is estimated that about 40 per cent of gas imports are used as feedstock for petrochemical plants while the remaining 60 per cent are consumed as follows: 31 per cent in combined heat and power plants; 12 per cent in the iron and steel industry; 12 per cent in the construction industry (cement, bricks, etc.); and 5 per cent in the glass manufacturing and other industries.

C. Gas Infrastructure

Due to the rather modest indigenous (proven) reserves of gas, the function of the Bulgarian pipeline network has mainly been to bring Russian gas into the country. In future, it will also be used to transit gas through to Yugoslavia and Greece. The two main systems, which begin at the Soviet border in the northeast, transport gas to large industrial consumers and combined heat and power (CHP) plants around the country, converging in Sofia. A new pipeline will branch off the southern system before it reaches Sofia, and continue from there towards the Greek and Yugoslavian borders. The nominal capacity of the present system has been indicated to be 9 BCM/year. An additional pipeline transmitting Soviet gas to Turkey runs along the eastern border of the country.

D. Planned Expansion of Infrastructure

The European Economic Community is subsidizing the construction of a pipeline from Bulgaria to Thessalonika in Greece, a spur of which will go to Skopje in southern Yugoslavia. The capacity of the system will be 9 BCM per annum. Preparations have been started in Macedonia for linking up with this major gas pipeline, which is expected to be operational by January 1994.

The Iranian pipeline to Western Europe through the Balkans is a project which has been considered for a long time. In spring this year, initial discussions were held between Greece and Iran. To be commercially attractive, we believe the line needs a throughput of at least 20 BCM per annum, probably even more. Other countries which have expressed an interest include Yugoslavia (1.5 BCM), Czechoslovakia (3 BCM) Bulgaria (1 BCM), Italy (2 BCM), and, without indication of potential off take volumes, Turkey, Romania, Poland, Austria and France.

E. Major Gas Purchase Contracts

In the past few years, Bulgaria has been importing around 6 BCM of gas annually from the Soviet Union. Although the contracts were converted to hard currency terms in early 1991, trade has continued on barter terms. Gas is received in exchange for bartered goods, as a loan repayment for rendered Bulgarian pipeline construction services, and as a transit fee.

In 1989, a 20 year contract was signed with Iran for yearly imports of 1 BCM of gas, scheduled to begin in 1990. Deliveries have, however, not yet taken place. The Iranian gas will be delivered via the Soviet transmission system. Press reports have indicated that the transit fee which is being demanded by the Soviet Union is too high for Iranian deliveries to be economically viable. Iran would receive Bulgarian chemical products in a counter trade arrangement in exchange for its gas deliveries.

F. Industry Structure

Production of oil and gas falls under the responsibilities of the Ministry of Industry, Trade and Services. Oil and gas is imported by the Khimimport Corporation, subordinated to the Ministry of Foreign Trade. Transmission is carried out by Bulgargas, which is a separate organization. Local distribution companies are responsible for low pressure lines feeding industrial facilities in their respective areas. Major users like CHP plants and large industrial consumers are responsible for their own internal distribution, and in some cases also control distribution lines.

G. Potential Contribution of Gas to Environmental Improvement

Current energy policy is based on continued utilization of indigenous, low quality brown coal to meet increases in demand for electricity. Six new coal fired units are included in the 1990-95 plan. Most other planned capacity additions will be small scale, clean coal technology CHP.

Compared with some of its East European neighbors, Bulgaria appears to suffer less severely from environmental problems such as air and water pollution. This is partly due to the relatively high proportion of electricity generated from hydroelectric or nuclear power. The water supply is, however, limited and irregular, so hydroelectric capacity needs to be supported by fossil-fueled alternatives. 51 per cent of the inland rivers and 36 per cent of total hydro potential has already been utilized. Also, the country's only nuclear power plant at Kozlodui is in bad condition. After a thorough examination, the IAEA came to the conclusion that for safety reasons it was imprudent to operate the plant given its condition. Some remedial action has since taken place and the plant is still in operation. Plans to continue construction on a half-built a second nuclear plant at Belene have been deferred due to strong environmental opposition.

Replacement of coal-fired capacity with gas fired CCGTs does not seem likely at present. Replacement of coal-fired capacity with CCGT power plants could, in theory, lead to an increase in annual gas demand of up to 5 BCM (given current electricity demand, and dependent on the amount of capacity replaced).

H. Prospects for Increased Indigenous Gas Production

Bulgaria is considered to have one of the best outlooks for additional onshore and offshore oil and gas discoveries in Eastern Europe. Foreign investment laws and exploration policies have recently been liberalized in an effort to attract investors. The area considered to contain oil and gas has been divided into ten onshore and six offshore blocks. Several Western operators have signed exploration contracts and joined the search for hydrocarbons in the Black Sea. Profits from commercial discoveries are to be divided equally between the foreign participants and the state; net profits must however not exceed 25 per cent of the total profits in convertible currency after fees and taxes.

I. Current Plans for Expansion of Gas Markets and Future Gas Supply and Demand

Being the smallest user of gas in Eastern Europe, Bulgaria represents the only country that is not planning to significantly increase gas purchases in the future. Unlike most of its neighbors, it is thus not expected to show an increase in gas demand in the near future. Gas is only used in industry, either as a feedstock (45 per cent) or for energy production (30 per cent), and in CHP plants (25 per cent). The only energy sources used by the residential sector are district heating and electricity.

Only the petrochemical sector is expected to require additional gas. Gas demand in this sector could, however, fall as petrochemical companies adapt to international competition. Neither the electricity authority nor the district gas companies foresee major increases in gas consumption for power generation or in the residential and commercial sectors. Previously, the attractiveness of low gas prices and environmental friendliness prompted construction of gas-based combined heat

and power plants. However, future plans are for incremental power generation based on clean coal technology.

Bulgaria is not very well endowed with natural resources. Apart from poor quality lignite, energy reserves are very limited. Natural gas has been used to substitute coal in city CHP plants for environmental reasons, but future plants are planned to use clean coal technology (fueled by lignite) rather than gas, which would have to be imported.

Moreover, most of the populated centers in Bulgaria are already connected to the gas grid, implying that district heating requirements are expected to remain relatively constant. Any increases in demand will probably be met by Iranian gas, which is currently delivered via exchange with the Soviet Union.

Contrary to the forecast by Bulgarian authorities, the Soviet Union hopes to develop additional gas demand by initiating, inter alia, a compressed natural gas program that would displace oil-based transport fuels, such as gasoline and diesel. A pilot gas station already exists in Sofia. The Bulgarians have apparently not responded explicitly to the Soviet interest in developing a new gas market niche.

J. Pricing Policy

Bulgaria has until recently continued its traditional policy of closely controlled prices. Energy prices have now been liberalized. On 3 June 1991 plans to price liquid fuels to international market levels were announced.

The primary effect of raising energy prices and constant wage levels in the short term will be a rapid decline in demand, particularly in the energy sector. Gas demand is less likely to be drastically reduced as it may be considered an essential item given its importance as raw material in production of exportable chemicals and fertilizers.

1991 Prices[a]	$/'000 m^3	$/MMBtu
Import price	95.00	2.52
Industry price	98.50	2.62
Commercial sector	98.50	2.62
Household sector	98.50	2.62

Source: World Bank
a. Represents estimated average 1991 price

K. Gas Demand Forecast

Our forecast for gas demand in Bulgaria predicts continued use of gas in the industrial sectors, with beginning development of residential demand from 2000 onwards in the high scenario. The low scenario represents our view of future gas demand given stagnant to slow economic development, no efficiency improvements, no replacement of coal fired capacity in power generation, and no development of other market segments. The high scenario represents gas demand under the assumption of strong economic growth, active development of gas market and

new customer segments (residential), some efficiency improvements and some replacement of coal fired capacity in power generation at the expense of coal.

Bulgarian Gas Demand

BCM	1990	1995	2000	2005	2010	Average Growth %
Low scenario	6.5	6.5	6.5	6.8	7.0	0.4
Base Case	6.5	6.6	7.1	7.4	7.7	0.9
High scenario	6.5	6.6	9.4	12.7	17.2	5.0
Indig. Production	0	0	0	0	0	0
Imports	6.5	6.5	6.5	6.5	6.5	-
Deficit	0	0-0.1	0-2.9	0.3-6.2	0.5-10.7	-

Source: Arthur D. Little

As can be seen from the table above, we predict that a supply gap of up to 3 BCM could develop by 2000, and between 0.5 and 11 BCM by 2010.

L. Supply Cost Curve

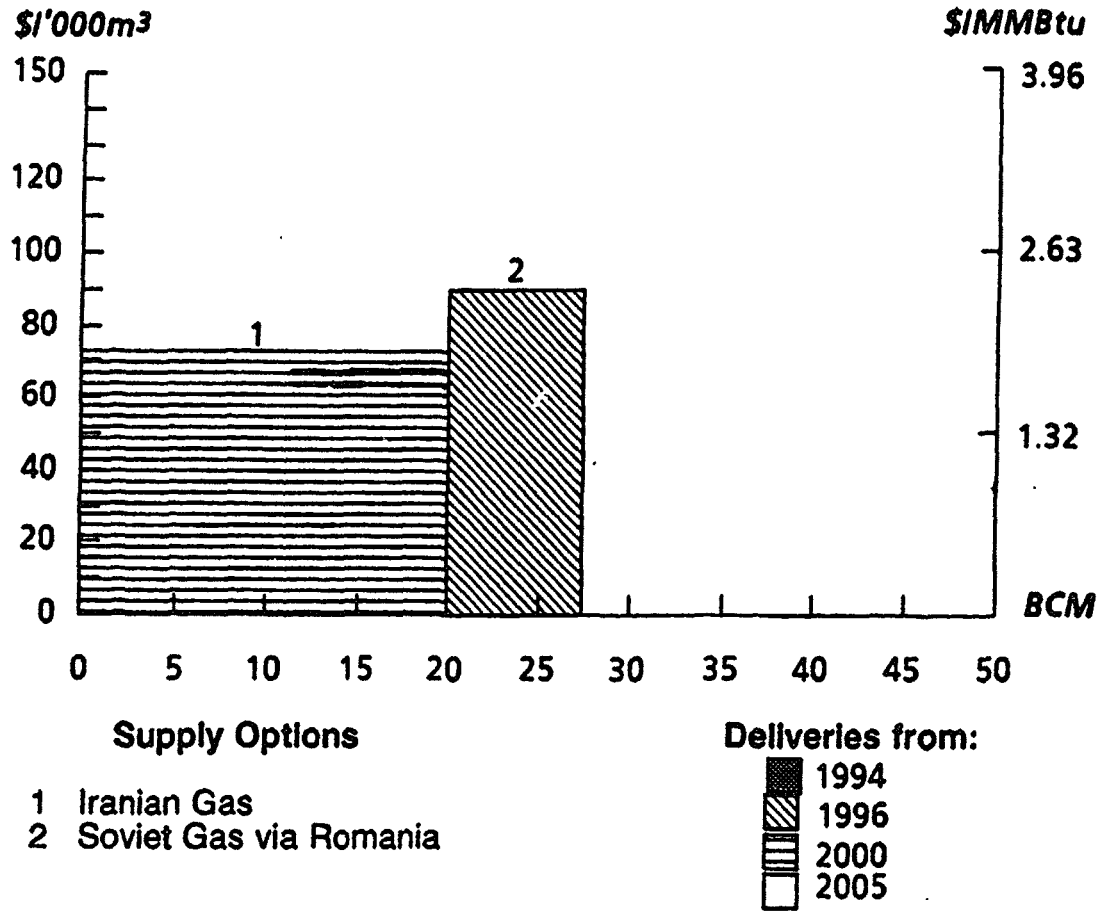
We have calculated the delivered cost of gas from two alternative supply sources to Bulgaria.

- Incremental gas from the Soviet Union, delivered from the Yamal peninsula via a 35 BCM pipeline to Jelets, with a subsequent 5 BCM branch to Romania, and a 2.5 BCM pipeline from Romania to Sofia; and

- Incremental Iranian gas volumes, delivered via the proposed new pipeline through Turkey to south eastern Bulgaria, continuing from the border to Sofia.

In cost terms, Iranian gas seems to be the cheapest supply source, but it is not likely to be available before 2000.

Supply Cost Curve for Bulgaria: Gas Delivered Sofia



Czechoslovakia

A. The Czechoslovakian Energy Industry - Summary

- Czechoslovakia's national primary energy fuel mix in 1989 consisted of 57 per cent coal, 21 per cent oil, 13 per cent natural gas and 9 per cent nuclear, hydro, and imported electricity (Source: IEA Energy Balances).
- Natural gas has been used in all market sectors since before the 1960s.
- Natural gas consumption has since the early 1980's, grown at an average 2.6 percent per annum.
- The natural gas grid is very well developed, with the main Soviet export pipeline to Western Europe crossing the country from east to west.
- The main problems facing the government of Czechoslovakia in the energy sector are the following:
  - Dependence on imported fuels as energy sources
  - High share in energy mix of indigenous low grade coal used in highly polluting industries and power plants
  - Dependence on the USSR as main source of imported fuels

    Need to extend gas infrastructure in order to permit imports from other sources
  - Urgent need to reduce air and water pollution without impairing ability to satisfy power demand
  - Lack of financial resources required for investment

B. Primary Energy Supply and Demand

The Czechoslovakian energy supply mix is dominated by coal, which accounts for over 57 per cent of total supply. The Czechoslovak coal deposits are almost entirely low quality, and recent environmental concerns may prompt a reduction of coal's share of energy supply in the future. In an effort to alleviate quality concerns, Czechoslovakia trades brown coal for lower sulfur hard coal from Poland. This trading allows a higher quality of coal to be burned domestically.

C. Historical Natural Gas Supply and Demand

Czechoslovakia has proven gas reserves of about 14 BCM (and proven plus probable of about 64 BCM). In 1989, production reached about 1 BCM. Indigenous production represents less than 7 per cent of total domestic gas requirements.

Gas demand was 9.6 BCM in 1989 and accounted for about 13 per cent of total energy demand, up from 9 per cent in 1980. Czechoslovakia imports most of its gas from the Soviet Union. A significant volume is received as transit fee payments for gas pipeline transmissions to Western Europe.

Gas consumption is concentrated in the power generation and industrial sectors which respectively accounted for 37 per cent and 25 per cent of total gas demand in 1989. Apart from 0.6 BCM used in the petrochemical industry, the industrial sector uses gas for steam-raising in a wide variety of processing/manufacturing activities. The residential and commercial sector accounted for 41 per cent, indicating an established gas transmission and distribution system.

Historically, gas demand has increased by 2.6 per cent per annum during 1980-89. A modest decline was recorded in industrial and power generation gas demand over this period, though this was more than offset by an almost 11 per cent increase in residential/commercial consumption.

D. Gas Infrastructure

The pipeline network was developed for the purpose of transporting Soviet gas to Germany and France. Instead of transit fees, Czechoslovakia received Soviet gas as payment. The Bratrstvo pipeline system (commissioned in 1975) connects the Progress pipeline at Uzhgorod on the eastern border with the Megal system at Waidhaus and Baumgarten in the west. One of the Brotherhood pipelines is used for local purposes, and has a capacity of around 5 BCM. The Brotherhood system could be expanded to permit increased imports of Soviet gas.

Bohemia and Moravia are well covered by transmission lines, while the Slovakian part of the system, although including a larger part of the Bratrstvo pipeline, has fewer branch lines.

In the past, the seasonal variation in gas consumption resulting from a high proportion of gas used for heating purposes has been a major problem. In 1989 two additional gas storage reservoirs were constructed bringing the total to five with an overall capacity of 3 BCM. There are now gas storage facilities both in Bohemia and Moravia, able to meet 40 per cent of total winter peak gas demand.

E. Major Gas Purchase Contracts

Having only minor indigenous reserves of gas, Czechoslovakia is the largest user and importer of Soviet gas in Eastern Europe. Gas is received in exchange for bartered goods and as a transit fee. Furthermore, 4.5 BCM is purchased from the Soviet Union at a reduced price in exchange for engineering work done by Czechoslavak companies on the Soviet gas pipeline system.

F. Industry Structure

The Ministry of Economy is responsible for the administration of two oil and gas companies, five coal production enterprises, two electricity companies and one company (Transitni Plynovod Praha), which operates the TransGas (Bratrstvo) transmission system. Oil and gas production is carried out by Naftovy A Plynarenske Priemysl Zapadnoslovenske through its

subsidiary Nafta Gbely. Energy imports are handled by the Chemapol Corporation, subordinate to the Ministry of Foreign Trade.

The two gas utilities, Czech-Moravian Gas (Ceske Plynarenske Podniky, CPP) and Slovak Gas (SPP), are both owned by the two republics. CPP, which handles gas distribution in Bohemia and Moravia, is planning to restructure the gas industry of the Czech Republic. CPP itself will be restructured into a holding company, with eight subsidiaries comprising 58 business units. It is not known to us whether SPP, which is the Slovakian equivalent of CPP, has similar plans, but it would seem likely, given the general trend towards restructuring and privatization present in the country.

A major point of dispute is the future ownership and control of the TransGas pipeline (built by CPP), which carries Soviet gas across Czechoslovakia to the German and Austrian borders. For the moment, ownership has been transferred to CPP (48 per cent) and SPP (52 per cent), but future foreign participation may be allowed. The two utilities are in disagreement over the relative size of their respective shareholdings. The Slovaks would like to see a separate company set up to manage the 72 per cent of the pipeline which run across their territory. Currently, TransGas' profits are split equally between the two Republics.

G. Potential Contribution of Gas to Environmental Improvement

Czechoslovakia has the second worst environmental problems in Eastern Europe (only Poland is worse) mainly consisting of air and water pollution. It has been recognized that the power generation sector is to a large extent responsible for the emissions of dust, sulfur, SO_2 and acids which pollute the air.

In 1989, 51 per cent of electricity was generated from coal (primarily lignite), 28 per cent from nuclear power, 8 per cent from gas, 8 per cent from oil and 5 per cent from hydro. The efficiency of existing coal plants is very low, 21 per cent as compared with 38 per cent for a modern Western plant burning hard coal.

In February 1991, it was reported that power stations in Northern Bohemia (where lignite is produced and many of the power plants are located) reduced their output by 776 MW to reduce pollution. Northern Bohemia is the most polluted region in the country, which is why the Government has decided to close down a number of lignite fired plants in this area. 50 per cent of total lignite generating capacity (600 MW) are to be closed down within five years, with the rest to be refitted with desulphurization equipment.

The question of how to replace this capacity is not an easy problem to solve. Hydro electricity has already been exploited close to its full potential and is unlikely to offer substantial possibilities for expansion. The government aims to increase the use of gas in power generation, but gas would have to be imported and paid for in hard currency and would increase its already significant share of primary energy demand and the country's dependency on imported fuels. An increase of nuclear capacity would require substantial outlays of capital. The government strongly favors expansion of the nuclear program, but has been met by protests from Austria.

We predict that given current electricity demand, replacement of coal-fired capacity with CCGT power plants could, theoretically, lead to an increase in annual gas demand of between 1.5 and 10 BCM (depending on the amount of capacity replaced).

H. Current Plans for Expansion of Gas Markets

According to plans drawn up prior to 1989, Czechoslovakia was to increase gas consumption from current 15 BCM per year to 25 BCM per year by 2005. The government is currently investing in conversion of about 14 CHP power plants in order to increase use of gas in power production.

I. Future Gas Supply and Demand

Despite limited domestic gas reserves, the Government is trying to reduce dependence on Soviet gas imports. Given Czechoslovakia's hard currency limitations and significant indigenous coal reserves, gas will, on an incremental demand basis, have a secondary role in the economy during the next few years, only growing by 1 per cent per annum.

Increased gas use will be seen in all sectors, but power generators and residential/commercial users are expected to have higher requirements than industrial users given the newly stated government priorities. The emerging government policy suggests that future gas developments affecting demand will focus on:

- The district gas system
- Conversion of combined heat and power plants; as well as
- Selected conversion of industrial boilers from coal and oil to gas.

Czechoslovakia plans to convert approximately 168 coal-based heating units to gas by 2000. The coal units currently consume about 2.8 million tonnes per year of lignite. Displacement of coal will require about 0.8 BCM per year of gas. However, with indigenous coal resources, it is unclear whether conversion will be economically attractive, though environmental benefits are becoming a major consideration.

The reliance on Soviet gas imports has prompted authorities to consider alternative supply sources, such as Algerian pipeline gas via Italy (and Austria), regasified LNG through a pipeline from the Adriatic, Norwegian pipeline gas or LNG, and/or Iranian pipeline gas.

J. Pricing Policy

Earlier in 1991, gas prices were increased to near market levels through a 134 per cent price rise as a result of price liberalization. The rise in gas prices in Czechoslovakia is expected to put some downward pressure on demand, particularly at the residential and commercial levels. Household gas prices rose by 130 per cent at the beginning of 1991, but are nevertheless still far below market price levels.

Czechoslovakia is thought to be in a better position than other East European countries given its historically tight monetary and fiscal policies. However, the economy had only partially moved to market-based pricing in 1990 and thus 1991 will require further price liberalization, particularly since wages have been allowed to increase in lock-step with prices. Higher gas prices are likely to affect residential and commercial gas sales more than the industrial and the power generation sectors.

K. Gas Demand Forecast

Our low scenario predicts slow economic growth, with gas demand increasing moderately in industry and power generation and more strongly in the residential sector. In the high scenario, which is based on strong economic growth and increased use of gas at the expense of other fuels (mainly coal), gas consumption is predicted to grow rapidly in all sectors.

Czechoslovakian Gas Demand

BCM	1990	1995	2000	2005	2010	Average Growth %
Low scenario	12.7	13.5	15.0	16.8	18.8	1.9
Base Case	12.7	13.7	16.8	20.8	26.0	3.6
High scenario	12.7	13.7	17.6	23.3	30.9	4.5
Indig. Production	0.7	0.7	0.8	0.8	0.8	
Imports	12.0	12.0	12.0	12.0	12.0	
Deficit	0	0.8-1.0	2.2-4.8	4.0-10.5	6.0-18.1	

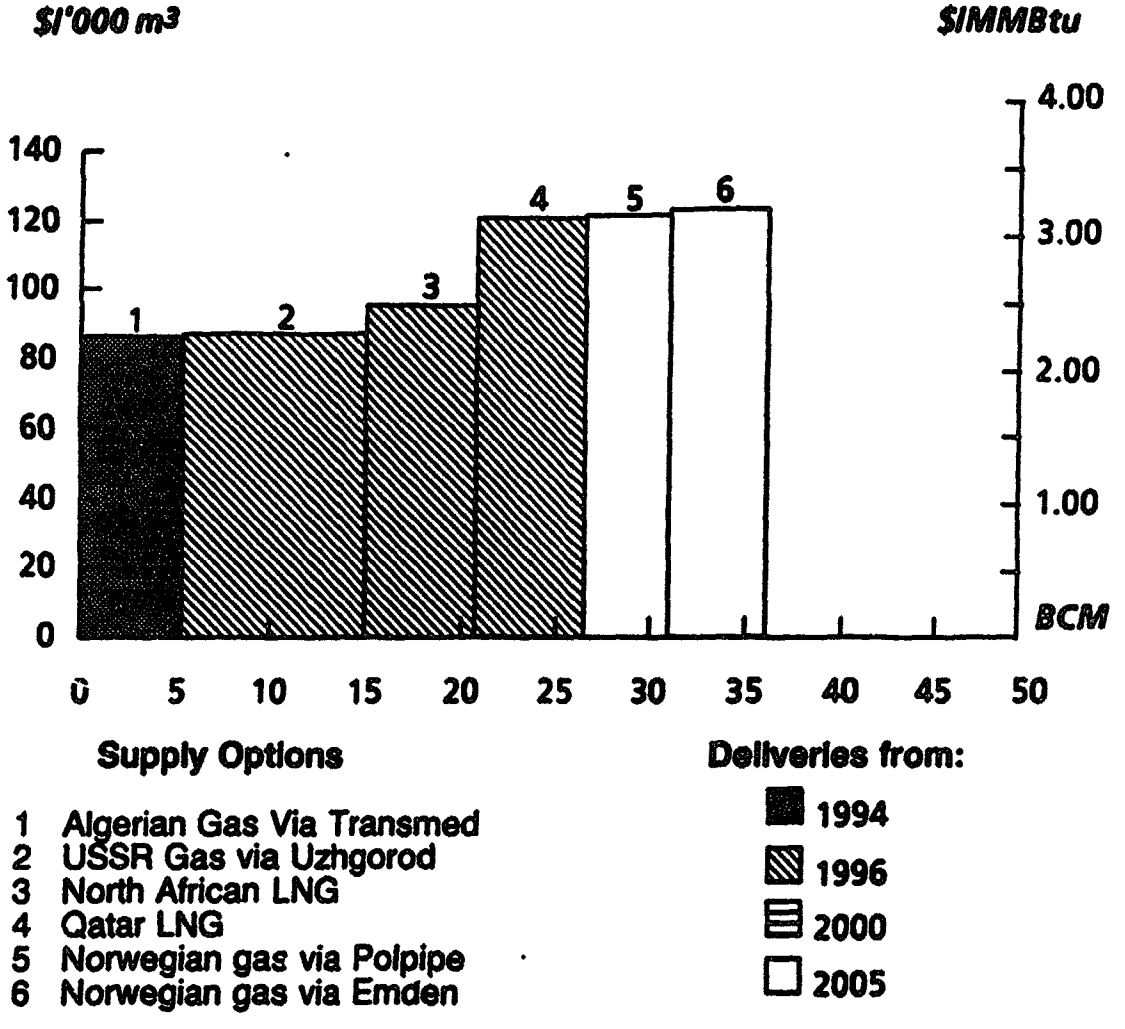
As can be seen from the table above, we predict a supply gap of around 1 BCM to have developed by 1995, 2 to 5 BCM by 2000 and 6 to 18 BCM by 2010.

L. Supply Cost Curve

We have calculated the cost of bringing incremental gas from the Soviet Union, Norway, and North Africa to Czechoslovakia. Soviet gas is assumed delivered at Uzhgorod, Norwegian gas via the proposed Polpipe line or Midal/Stegal to Litvinov, Algerian pipeline gas from Monfalcone on the Yugoslavian/Italian border, and regasified Libyan/Algerian LNG from the proposed terminal at Omisalj in Yugoslavia.

The shorter internal distance from Litvinov to Prague does not seem to offset the cost disadvantage of Norwegian gas. Algerian pipeline gas seems to be the least costly non-Soviet supply alternative for Czechoslovakia in the short to medium term (deliveries starting before 2000).

Supply Cost Curve for Czechoslovakia: Gas Delivered Prague



Hungary

A. The Hungarian Energy Industry - Summary

- Hungary's national primary energy fuel mix in 1989 consisted of 24 per cent coal, 30 per cent oil, 31 per cent natural gas and 15 per cent nuclear, hydro, and imported electricity (Source: IEA Energy Balances).
- Natural gas has been used in all market sectors since before the 1960s.
- Natural gas consumption has since the early 1980's grown at an average 3 percent per annum, primarily at the expense of coal and oil.
- The natural gas grid is well developed, covering most of the country and reaching most areas of large energy consumption.
- The main problems facing the government of Hungary in the energy sector are the following:
  - Highly dependent on the USSR as main source for imported fuels
  - Proven/recoverable gas reserves nearing depletion
  - Need to increase domestic gas production by finding new reserves and improving recovery on presently producing fields
  - Need to extend gas infrastructure in order to permit imports from other sources
  - Need to reduce air and water pollution without impairing ability to satisfy power demand
  - Lack of financial resources required for investment
  - Need to improve energy conservation
  - Need to increase base load power production capacity.

B. Historical Natural Gas Supply And Demand

In 1990, Hungary had remaining proved plus probable reserves estimated at 26 million tonnes of oil and 123 BCM of gas. Under the most recently completed five year plan (1986-90), OKGT (the former government organization in charge of oil and gas activity, now called MOL) drilled an average of 200,000 meters of exploratory wells and 170,000 meters of development wells each year. At an average depth of 2,100 meters, this amounts to about 95 wells per year. Reserves are expected to be depleted quite rapidly over the short term as funds are invested in secondary and tertiary recovery projects.

Natural gas accounted for about 31 per cent of total energy demand in 1989, up from about 26 per cent in 1980, of which about half is domestically produced and the remainder imported from the Soviet Union. While the share of gas in primary energy demand has been increasing, coal has declined by about 4 per cent and oil by about 10 per cent. This decline was partially offset by increases in hydro and nuclear power, which rose from 2 per cent of primary energy demand in 1980 to 15 per cent in 1989.

Total natural gas consumption was 9.9 BCM in 1989. Gas is primarily used for power generation and in industry. In 1989, power generation accounted for about 46 per cent of total gas demand and was used to generate about 14 per cent of total electricity production. The second largest user of gas is the industrial sector, which accounted for 31 per cent of total demand and is comprised primarily of petrochemical, iron and steel and energy sector end-users. The residential sector accounts for 18 per cent of total gas demand, while energy transformation, own use and losses together accounted for 4 per cent of total demand.

Overall, gas demand has grown at a moderate rate during the 1980s, increasing from 7.5 BCM in 1980 to 9.9 BCM in 1989, an average annual increase of 3 per cent. Gas demand growth has occurred primarily in the residential sectors, which grew at an average 14 per cent annually from 1980-89. (Source: IEA, 1 MTOE = 0.957 m3 of natural gas, assuming 40 MJ gcv per standard m^3).

C. Gas Infrastructure

Hungary has sizable natural gas reserves which were discovered in the 1960s. The pipeline network was developed to distribute indigenously produced gas from fields scattered in the eastern part of the country to major centers of consumption, namely the consumer districts of Budapest, Central Hungary and Transdanubia. Gas imported from the Soviet Union is delivered at Beregdaroc via the Bratrstvo system, the capacity of which has been increased continuously. Transit gas to Yugoslavia is supplied via a pipeline beginning in the vicinity of Budapest to Horgos on the Yugoslavian border (commissioned in 1979 and expanded in 1983).

At the end of 1988, Hungary's remaining proven and probable gas reserves were approximately 115 BCM. Although the reserves are there to be produced, the Hungarians have problems in retrieving them, as production costs are increasing due to inefficient and outdated equipment. In 1989, some 5 BCM were produced, but output is expected to drop to 4 BCM per year by 2000.

The Hungarian residential segment is well penetrated. 35 per cent of households are supplied with piped gas (a further 59 per cent currently use bottled gas). Underground gas storages exist at Hajduszoboszlo, Kardoskutt and Pusztaedevics. There are two main gas gathering stations with a combined capacity of 11.5 BCM per year.

D. Major Gas Purchase Contracts

Hungary has two contracts with the Soviet Union. The Orenburg contract, which is for deliveries of 2.7 BCM per year, may be extended beyond the 1992 expiry date, subject to revision to adapt to new market conditions. The Yamburg contract stipulates deliveries of 1.9 BCM per annum from 1989 to 1998, which will be supplied to compensate Hungary for its contributions to the construction of the Progress pipeline.

OKGT (now MOL) reached an agreement with the Yugoslav companies Energopetrol and Naftagas on delivery of 67 BCM of gas for 20 years, to be delivered between 1997 and 2017. Supplies will build up to 3.6 BCM per year by 2000.

E. Industry Structu

The energy sector was previously controlled by the Ministry of Industry and administered through a number of trusts. The former National Oil and Gas Trust, OKGT, was responsible for and had monopoly control over exploration, production, processing, and transport of natural gas and oil. OKGT also managed seven other regional oil and gas production administrations, and the Oil and Gas Pipeline Administration (Gaz-es Olajszallito Vallalat). Two affiliated companies, NKFV and KFV, handled production, processing, and marketing of natural gas and operate underground storage facilities. There were five regional gas companies, which handled regional distribution activities. Trade in oil and gas was undertaken by the Ministry of Foreign Trade through its organization Mineralimpex.

A reorganization of the Hungarian industry has recently taken place. At the beginning of 1991, reorganization of the energy sector commenced with the official decision to disband the state energy combine OKGT, which has now been transformed into a joint stock company, the Hungarian Oil and Gas Corporation (MOL). Twelve affiliated companies have been separated from the former OKGT, including the five distribution companies. The government has announced that access to excess capacity in MOL's pipelines will be introduced. The state will retain 50 per cent of the equity in the regional companies, while the rest will be privatized with no limit on foreign participation. Production of oil and gas, refining, transport and marketing is to be transferred to a new joint stock company, which initially will be state-controlled, but may later be privatized. Imports have now been liberalized and Mineralimpex's monopoly broken, leaving MOL free to take import natural gas to Hungary. Although Hungary is generally regarded as having the best climate for foreign investment in Eastern Europe, lack of government direction has so far hindered constructive decision making and kept the gas industry firmly under state control.

F. Potential Contribution of Gas to Environmental Improvement

In 1989, 46 per cent of Hungarian electricity was generated from nuclear plants, 26 per cent from coal, 14 per cent from gas, 13 per cent from oil and the rest from hydroelectric capacity. Hungary's air is less polluted than that of most its neighbors, with the exception of Yugoslavia. Pollution could potentially be reduced if coal-fired capacity were to be replaced by natural gas-fired units.

Hungarian power generation capacity, given that existing nuclear capacity is not shut down due to safety problems, is sufficient not to require construction of new base load power plants until after the year 2000. By then, electricity demand will have increased by the equivalent of about 1 GW of capacity, which could be met by constructing gas-turbine and combined cycle plants. Given current electricity demand, replacement of coal-fired capacity with CCGT power plants could, in theory, lead to an annual increase in gas demand of between 0.5 and 1.5 BCM (depending on the amount of capacity replaced).

G. Prospects for Increased Indigenous Gas Production

Gas production in Hungary could increase significantly in the second half of the 1990s as the Pannonian basin, which extends into Yugoslavia and Romania, is believed to be highly prospective. Five concessions are being offered to foreign companies to be awarded by the end of 1992. Tougher terms in Soviet import contracts imposed at the beginning of 1991 have made the search for domestic gas more urgent. To sustain current production levels, heavy investment would need to be made in modernizing and improving the efficiency of gas production equipment.

The Hungarian government expects to award exploration concessions to foreign companies toward the end of 1992. Gas prospects are thought to be good, particularly in the Pannonian Basin which extends into Yugoslavia and Romania. The search for domestic gas reserves will be increasingly attractive as the Soviets continue to seek payment in hard currency.

H. Planned Expansion of Infrastructure

In Hungary, a new line is to be built from Beregdaroc on the Soviet border leading through Hajduszoboszlo and Szeged to the Yugoslav reception station at Horgos. From there it will continue some 600 km into Yugoslavia, ultimately leading to Belgrade. It will have a diameter of 820 mm for the first 123 km, where at least 1 BCM per year of its projected annual capacity of 8.8 BCM will be sent to an underground gas storage reservoir for subsequent despatch through Kisujszallas, Szolnok and Szeged to Budapest.

The remaining gas will continue southward to Yugoslavia, with up to 3.5 BCM/year available for consumption in southern Hungary. It is estimated that the pipeline will cost around $50 million, 50 per cent of which will be financed by the Yugoslavs by a $25 million loan, which Hungary will repay with low transit fees for 8 years.

In late 1990, OKGT (MOL) signed an agreement with seven Yugoslav companies, Metalimpex of Czechoslovakia and Austria's OMV to examine the possibility of importing 8-10 BCM of LNG per year via a regasification
terminal to be constructed on the Adriatic coast either at Koper or Omisalj. In addition, a plant for enrichment of poor quality gas is under construction near Tazlar.

The World Bank is engaged in a project analyzing the feasibility of a pipeline connection with the Austrian transmission system from Baumgarten or Fischamend (TAG) to Györ (approximate distance 130 km), allowing imports of gas from Austria (out of its portfolio of indigenous, Norwegian, and Soviet gas). Another option which is being studied is an additional connection with the Czechoslovakian transmission system at Ivanka to Györ (90 km), allowing increased imports of Soviet gas.

I. Pricing Policy

Price liberalization has been introduced for oil products, with consequent rises in energy prices. Gas prices are still regulated. Gas prices for household consumers rose by 50 per cent on June 1, 1991.

Hungary is presently experiencing a high inflation rate (30 per cent). The primary effect if prices are raised and wages held constant will be a rapid decline in demand, particularly in the

energy sector. Gas demand, however, is less likely to be drastically reduced as it will likely be considered an essential item given its importance in the residential and commercial sectors for heating. Lower priority uses such as the petrochemical sector and certain industrial applications will take lower priority in terms of allocation of limited gas imports and as such could have lower demand in the future.

October 1991 Prices	$/'000 m^3	$/MMBtu
Industry	111.32	2.95
Commercial sector	164.53	4.36
Household sector	122.26	3.24

Source: World Bank

J. Gas Demand Forecasts

Our high scenario for future Hungarian gas demand is based on strong economic growth, replacement of coal-fired capacity, increased demand for gas in all market segments, and improvements in end-use efficiency. In the low scenario, we have assumed slow economic growth, stagnating to slow growth in gas demand in all sectors and no replacement of coal-fired capacity.

Hungarian Gas Demand

BCM	1990	1995	2000	2005	2010	Average Growth %
Low Scenario	11.3	11.6	12.6	14.5	17.1	2.1
Base Case	11.3	11.6	12.7	16.1	19.4	2.7
High Scenario	11.3	11.6	15.5	20.7	27.7	4.6
Indig. Production	5.3	5.6	4.2	4.2	4.2	
Imports	6.0	6.0	6.0	6.0	6.0	
Deficit	0	0	2.4-5.3	4.3-10.5	6.9-17.5	

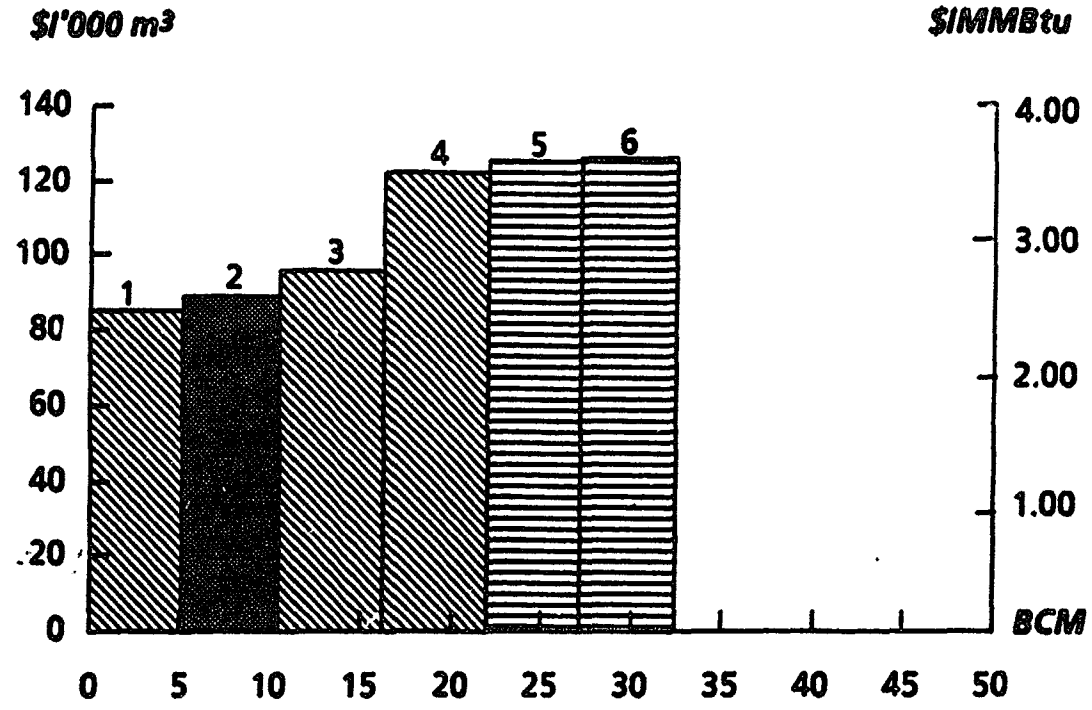
Source Arthur D. Little

As can be seen from the table above, we estimate that by 2000, a supply deficit of about 2.4 to 5.3 BCM may have developed, growing to 6.9 to 17.5 BCM by 2010.

K. Supply Cost Curve

The cost situation of Hungary is similar to that of Czechoslovakia. Of the non-Soviet supply alternatives, Algerian pipeline gas delivered via Transmed and Monfalcone is the least costly. Soviet gas is cheaper in Budapest than in Prague, due to the shorter transport distance from Uzhgorod. As visualized in the chart, Norwegian gas would be considerably more expensive to deliver to Budapest.

Supply Cost Curve for Hungary: Gas Delivered Budapest



Supply Options

1 Soviet Gas via Beregdaroc
2 Algerian gas via Transmed
3 North African LNG
4 Qatar LNG
5 Norwegian gas via Polpipe
6 Norwegian gas via Emden

Deliveries from:

1994
1996
2000
2005

Poland

A. The Polish Energy Industry - Summary

- Poland's national fuel mix in 1989 consisted of 78 per cent coal, 14 per cent oil, 8 per cent natural gas and 0.5 per cent nuclear and hydro electricity (Source: IEA Energy Balances).

- Natural gas has been used in most market sectors since before the 1960s. Use of gas in the residential and power generation sectors began in the mid to end 1970s.

- Natural gas consumption has, since the early 1980's, grown very slowly at an average of less than 0.5 percent per annum.

- The natural gas grid is not very well developed, covering most of the country but having only limited throughput capacity.

- The main problems facing the government of Poland in the energy sector are the following:

  - Heavy reliance on domestic coal as primary source of energy, used to produce electricity in inefficient and highly polluting power plats as well as in all other market sectors

  - Highly dependent on the USSR as single source of gas imports

  - Proven/recoverable gas reserves nearing depletion

  - Need to find additional gas reserves and improve production facilities in order to maintain/increase indigenous production levels

  - Substantial need to extend gas infrastructure in order to meet demand targets and to permit imports from other sources

  - Need to reduce air and water pollution without impairing ability to satisfy power demand

  - Need to greatly improve efficiency in energy end-use and to replace polluting and inefficient boiler capacity

  - Lack of financial resources required for investment.

B. Primary Energy Supply and Demand

Poland is the largest consumer of energy in Eastern Europe, by far exceeding the total consumption of for example Yugoslavia (119 MMtoe as compared with 44 MMtoe), despite the fact that its gross domestic product only amounts to about 70 per cent of Yugoslavia's. Its population is however the largest in Eastern Europe, exceeding that of Yugoslavia with about 50 per cent.

About 80 per cent of Poland's own total energy needs are satisfied by coal, a proportion that has increased only slightly since 1980, consistent with moderate growth in overall energy demand. In addition, Poland, along with the Soviet Union, is a significant hard coal exporter to other East European countries and the West. Poland's coal is mostly high quality hard coal, and as such has the potential to help both Poland and the surrounding countries to meet future growth in energy demand and improving the environment.

Poland has historically exported the higher quality hard coal and used lignite domestically in order to maximize foreign exchange earnings. However, the recent economic reforms have prompted large increases in all domestic coal prices, thus reducing the relative attractiveness of this fuel compared to oil or gas (despite the fact that oil and gas prices have also increased). As mines are given autonomy in the future and state subsidies are cut, local demand is expected to decline in the near term. On the supply side, rationalization of inefficient and unprofitable coal mines is expected to reduce output.

Exports to both Eastern Europe and the West are expected to continue in order to provide Poland with a major source of hard currency. Currently, coal accounts for 98 per cent of electricity generation, but this is expected to decline in the future in order to help reduce emissions.

C. Historical Natural Gas Supply and Demand

Poland's most recent assessment of proven onshore gas reserves is about 130 BCM, significantly lower than previous figures reported by Polish authorities. Coal-bed methane reserves could add substantially to indigenous gas reserves.

Gas demand was 9.6 BCM in 1989, up from 8.9 BCM in 1980. This represents a relatively small 7 per cent share of energy demand, a figure that has remained constant since 1980. Poland produced over 50 per cent of its gas requirements indigenously as recently as 1985, but since then domestic gas output has declined. Additional imports from the Soviet Union have made up for the shortfall.

The majority of gas consumption is in the industrial sector which accounted for almost 54 per cent of total demand in 1988. The residential and commercial sectors consumed about 36 per cent of the total while power generation (including district heating), which is principally fueled by coal, accounted for 6 per cent.

Historically, total gas demand has grown very slowly at less than 0.5 per cent per annum during 1980-89. However, this masks strong growth in the residential and commercial sectors where gas use increased by over 5 per cent per annum as a result of expansion of the gas distribution network. Other uses of gas increased much more slowly during the 1980-89 period.

D. Gas Infrastructure

The Polish gas network was developed to distribute imported Soviet gas and indigenously produced gas from southeast Poland, where the Soviet pipeline enters the country and producing gas fields are located. Poland has three separate gas transmission networks, one for high calorific value gas, one for low calorific value gas and one for coke oven gas. The three systems span most of Poland, but have only limited throughput capacity. In order to reach the targeted increase in gas demand the system would have to be expanded substantially. Remaining

recoverable Polish reserves have been estimated to 134 BCM, but may be lower. Current production is about 3 BCM per year.

E. Industry Structure

Polskie Gornistwo Naftowe i Gazownistrol (POGC), [illegible] blic utility enterprise of the Ministry of Commerce, Mining and Power, administers 22 re[illegible] [illegible]nizations responsible for exploration and production of oil and gas. Distribution of gas is handled by distribution companies, such as the Polish Gas Corporation of Warsaw.

The POGC is responsible for exploration, production, transmission and distribution of gas. It controls six regional gas utilities. Responsibility for gas imports formerly rested with Weglokoks, although negotiations were mainly carried out by the government.

Gas pipelines are administered by regional enterprises such as the Mazowieckie District Enterprise for Exploitation of Gas Pipelines, which is responsible for all pipelines in eastern Poland including the line from Kobrin to Warsaw and its branches.

The division of responsibilities between the Government and the state-owned energy companies is rather unclear. The Ministry of Industry exercises control over the management and activities of energy companies. The Government is moving towards a restructuring of the gas sector, assisted by the World Bank. The first move will be to divide the industry into separate business segments which will be encouraged to operate more along commercial lines. At a later date, private capital may be invited to participate in some or all of them.

F. Potential Contribution of Gas to Environmental Improvement

Environmental pollution is a severe problem, caused by emissions produced by the power generation sector and by industry. 96 per cent of Polish electricity is generated from coal (lignite plus high sulfur hard coal).

Realizing that it will not be possible to substitute this massive dependence on coal, the government first and foremost aims to clean and improve the quality of the coal which is burnt in power plants. The first priority in confronting Poland's environmental problems will be the control of emissions of particulates, sulfur and nitrogen oxides. Desulphurization plants are planned, initially for seven power stations using high sulfur hard coal or lignite.

The government expects that the coal industry will be able to finance the coal cleaning program. Investments required to reduce SO_2 would, however, be very large. The Polish Electricity Transmission Board estimates that a realistic program would cost $1 billion, hoping that foreign aid and investment will provide much of the capital required.

Given current electricity demand, replacement of coal-fired capacity with CCGT power plants could, theoretically, increase annual gas demand by between 15 and, if all coal-fired capacity was replaced with gas, 27 BCM.

G. Prospects for Increased Indigenous Gas Production

If indigenous gas production is to increase in Poland, more investments will be needed to step up exploration activities and improve recovery on producing fields. Exploration activity centers around an effort to make Poland self-sufficient in gas by 1996 through coal-bed methane recovery. One out of several existing schemes for coal-bed methane recovery is being promoted by Pol-Tex Methane Company, a joint venture formed by McKenzie Methane - Poland of Texas, United States and the Jastrzebie hard coal mining company. The company is expected to invest $36 million to develop about 5-6 BCM of natural gas from coal seams which will not be mined in the future.

Proven reserves amount to between 130 and 150 BCM of gas. The potential for new discoveries is considered to be high, reserves are estimated to exceed 600 BCM. Since exploration activities require large amounts of capital, the oil and gas sector has been specially targeted for promotion of foreign investment opportunities. The Polish Government is trying to improve terms and conditions in order to facilitate and attract more investment. The World Bank and European Investment Bank have provided loans of $310 million for development of the Polish gas industry, which will be used to improve indigenous production.

H. Current Plans for Expansion of Gas Markets

The government is aiming to increase the use of gas wherever possible, mainly for environmental reasons. A doubling of current consumption is envisaged by the year 2000. Plans include increasing use of gas in power generation. New gas fired capacity of 1.9 GW is to be constructed, which in 2005 will equal 5 per cent of total installed capacity. Great emphasis is also being placed on the need to increase energy efficiency, and a lot of effort will be put into reaching Western efficiency levels.

The problem the government is facing in trying to realize all these aims is to find reliable supply sources. Discussions are being held with both Norway and Algeria, so far without positive results.

I. Planned Expansion of Infrastructure

Poland has ambitious plans for expansion of its gas infrastructure in order to increase utilization of indigenous reserves as well as bring in additional imported supplies. The Soviet and Polish Governments are planning the construction of an additional pipeline from the Urals to the Polish border, intended to bring gas from Western Siberia to Poland.

Furthermore, a pipeline which could carry 6 BCM of North Sea gas to Poland, connecting the Polish and Danish transmission systems, is being studied by the POGC and DONG. The new pipeline (Polpipe), from Rodvig on the Danish island of Zealand to Niechorze on the Polish Baltic coast, would be 225 km long and require capital investment of $600 million (excluding investment in required new infrastructure on the Norwegian Continental Shelf). From the Baltic Coast, the pipeline would continue to Eastern Germany, Czechoslovakia and Hungary.

J. Pricing Policy

The Polish economy experienced very rapid inflation in 1989. Since then, inflation has been brought under control by a rigorous fiscal regime. Energy prices have been increased as part of the price liberalization program. There was a new increase on May 27, 1991, when household gas prices rose by 150 per cent and industry prices by 20 per cent. Aid is to be made available to those on low incomes.

Poland is expected to continue its move to market based pricing from action taken earlier this year. A substantial increase in gas prices was already enacted in early 1991, but additional price increases will be required to move totally to market prices. Furthermore, cross-subsidization is significant since the gas price increases have taken place only in selected sectors.

Mid 1991 Prices	$/'000 m^3	$/MMBtu
Import	93.00	2.46
Industry	116.87	3.10
Household	96.05	2.55

Source: World Bank

K. Gas Demand Forecasts

Our high scenario is based on strong economic growth and rapid replacement of coal in all sectors, with gas growing especially fast in the residential sector. In the low scenario, economic growth is slow to stagnant, gas replaces coal in the residential sector, but maintains its market share in all others.

Polish Gas Demand

BCM	1990	1995	2005	2000	2010	Average Growth %
Low scenario	10.1	11.1	12.5	14.6	17.1	2.7
Base Case	10.1	11.1	13.5	16.7	21.2	3.8
High scenario	10.1	11.5	14.9	20.2	28.3	5.3
Indig. Production	3.3	3.3	4.2	5.3	6.8	
Imports	6.8	8.0	8.0	8.0	8.0	
Deficit	0	0-0.2	.3-2.7	1.3-6.9	2.3-13.5	

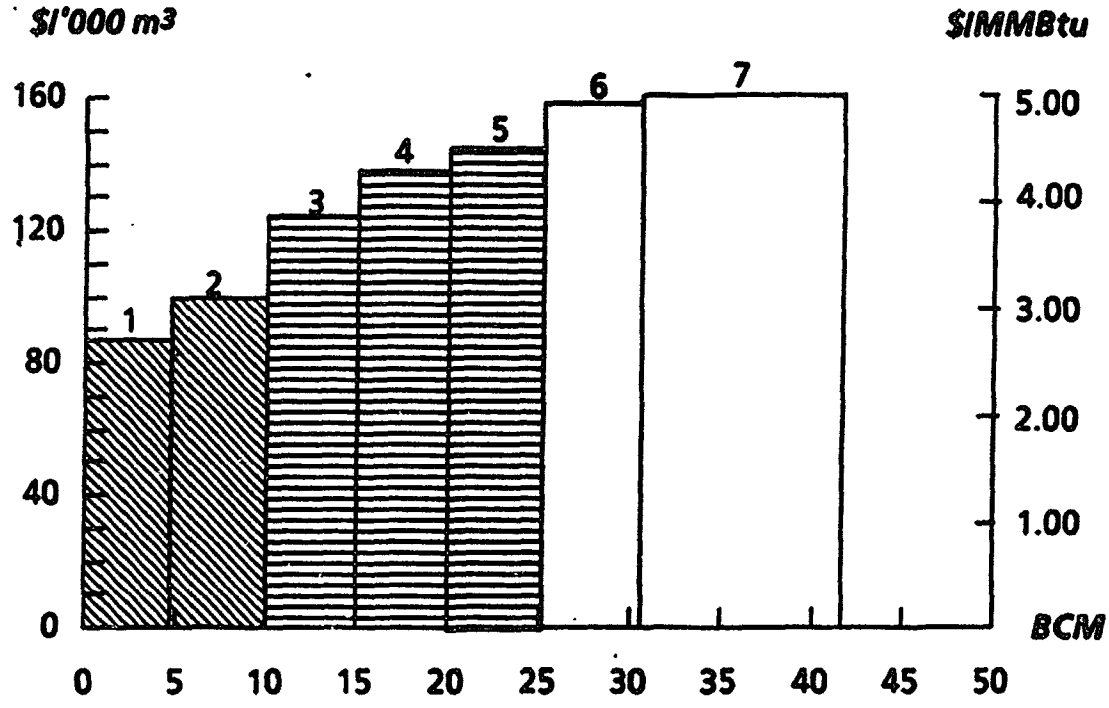
Source: Arthur D. Little

As indicated in the table above, we predict that a supply gap of between 0.3 and 2.7 BCM will have developed by 2000, growing to between 2.3 and 13.5 BCM by 2010.

L. Supply Cost Curve

In the short to medium term (deliveries beginning before 2000), incremental Soviet gas volumes are the least costly and also the only sources realistically available to Poland. North African LNG delivered Poland would be more costly than Soviet gas. Despite the longer transport distance, Soviet gas from West Siberia is cheaper if delivered via a large new pipeline to Uzhgorod with a subsequent smaller branch to Warsaw than through a dedicated branch to Brest-Litovsk.

Supply Cost Curve for Poland: Gas Delivered Warsaw



Supply Options:

1 Soviet gas via Uzhgorod
2 Soviet gas via Brest-Litovsk
3 Norwegian gas (Polpipe)
4 Soviet gas (Barents Sea) via Brest-Litovsk
5 Norwegian gas via Emden
6 Norwegian LNG via Gdansk
7 Soviet LNG (Barents Sea) at Gdansk

Deliveries from:

1994
1996
2000
2005

Romania

A. The Romanian Energy Industry - Summary

- Romania's national primary energy fuel mix in 1989 consisted of 30 per cent coal, 23 per cent oil, 45 per cent natural gas and 2 per cent nuclear and hydro electricity (Source: IEA Energy Balances).
- Natural gas has been used mainly in the industrial sectors since before the 1960s.
- Natural gas consumption peaked at 36 BCM in 1985 and has since fallen by an average 1.5 per cent per annum.
- The natural gas grid is well developed, covering most of the country with transmission and distribution lines.
- The main problems facing the government of Romania in the energy sector are the following:
  - Declining indigenous oil and gas production due to depletion of existing fields
  - Urgent need to increase gas reserve base and improve production facilities in order to maintain/increase indigenous production levels to meet short term demand through adaptation of appropriate exploration policies
  - Dependence on a single source of gas imports (USSR), which have been cut back substantially after the 1991 trade agreement
  - Need to reduce air and water pollution without impairing ability to satisfy power demand
  - Lack of financial resources required for investment.

B. Historical Natural Gas Supply and Demand

Romania has the largest reserves of oil and gas in Eastern Europe. Associated natural gas deposits are concentrated in the oil-bearing fields in the south and south-east of the country. Non-associated natural gas fields are located in the Transylvanian Basin, where high quality gas is produced and utilized as a petrochemical feedstock. Estimates of remaining reserves have not been published but are believed to be between 160 and 190 BCM. During the 1980s, there has been an overall decline in gas production due to lack of investment in the energy sector. The outlook in the post-Ceausescu era appears more favorable. Six Romanian rigs are actively drilling for oil and gas in the Black Sea, with production already beginning in two fields reported to have modest reserves. Western companies are expected to assist the government in the upstream sector in the near future.

Romanian gas demand, which is supply driven, was 34 BCM in 1989, compared with 36 BCM in 1985 and 34 BCM in 1980. In 1990, natural gas consumption fell to 28 BCM, of

which over 80 per cent was used in industry and for power generation. Gas represented 45 per cent of the total energy supply in 1989, the highest figure of any East European country and one which has declined only slightly from about 48 per cent during the early 1980s. Of the total gas supply, 82 per cent was produced domestically (1989) while the remainder was imported from the Soviet Union. Gas imports have been increasing, especially since 1987, as domestic production has declined due to field operation difficulties, pipeline problems and strikes. Imports from the Soviet Union have, however, under the 1991 trade agreement, been cut back substantially from their 1990 level of 8 BCM to an annual 3 BCM. The decline in domestic production was especially pronounced from 1988 to 1990 when domestic production fell by almost 9.4 BCM, of which only 4.2 BCM was offset by increased imports.

Gas consumed by the petrochemical sector has remained about constant. Recently, a shortage of electricity and gas feedstock for petrochemical plants has resulted in power shortages and a major downturn in petrochemical output. Fertilizer and methanol plants were operating at about 52 per cent of capacity during 1990 and were thought to have shut down during the winter of 1990/91 without any announced reactivation. Gas supplies, which have dwindled during 1991 due to strikes in the energy industry, are being diverted to the now higher priority residential and commercial sectors for lighting and heating requirements.

C. Gas Infrastructure

Romania's transmission and distribution systems were developed to distribute indigenously produced gas to main centers of consumption around the country. Gas is imported from the Soviet Union via a pipeline entering Romania from the east. Apart from an area in the Carpathian mountains, the country is relatively well covered with both transmission and distribution lines. The gas distribution system covers some 25,000 km. Romania has Eastern Europe's largest gas fields, located primarily in the south and southeast of the country and in the Transylvanian Basin. Natural gas is accounting for over half of the country's energy production. Reserves are, however, being depleted at an excessive rate, and will be exhausted by the late 1990s if the current production rate is maintained, unless new discoveries are made. Total gas production in 1990 was 28 BCM (down 12.5 per cent from 1989) and is expected to fall to 25 BCM in 1991.

D. Industry Structure

Romania's energy sector is still firmly under government control. A new natural gas corporation, Romgaz, was created in early 1991 to take over the assets and activities of an organization known as Gas-Methan or Gas-Central (which was an autonomous public sector enterprise). The company explores for, produces, transports and distributes natural gas within Romania. Associated gas is produced by Petrom, a state-owned national oil company which is involved in domestic exploration for, and production of, oil. State-owned Petrolexport exports and imports petroleum products and natural gas.

E. Potential Contribution of Gas to Environmental Improvement

In 1989, 41 per cent of Romanian electricity output was generated from coal (mainly lignite), while gas contributed with 25 per cent, hydro with 17 per cent, and oil with 18 per cent. Romania has, in recent years, had a policy to use indigenous low calorific value coal for power generation. Many old coal-fired plants are, however, in bad need of repair due to damage caused

by burning too low quality fuels. If lignite-fired capacity were exchanged for modern gas-fired CCGT power plants, substantial reductions in atmospheric pollution could be achieved. We predict that given current electricity demand, replacement of coal-fired capacity with CCGT power plants could, in theory, lead to an annual increase in gas demand of between 1.5 and 6 BCM (depending on the amount of capacity replaced).

F. Prospects for Increased Indigenous Gas Production

Non-associated gas production in 1989 was only 18 BCM from an estimated reserve of 91 BCM. Non-associated gas production will continue to decline unless new reserves are discovered. At the present level of production, non-associated gas reserves will soon be exhausted (early 1990s). In order to offset the rapid decline in production levels, Romania is hoping to be able to cut back flaring of associated gas.

A region with gas potential is thought to be the Black Sea, where it is estimated that some 100 BCM may be located. Exploration and production is, however, bound to be expensive. The government has initiated a comprehensive assessment of the country's hydrocarbon potential which is to be financed by a World Bank Technical Assistance loan. The study is aimed at identifying areas which have good gas potential, including the Carpathian mountains. Foreign investors have been invited to bid for 13 exploration blocks. However, due to logistical and legal constraints, this has been delayed, although many companies have indicated a preliminary interest to participate for development of the gas sector.

G. Future Gas Supply and Demand

Romania is expected to maintain indigenous production at the 1990 level of 25 BCM through 2000 as a result of increased investment from Western private and institutional organizations and technical assistance for field maintenance. In the short term, imports from the Soviet Union as well as cuts in flaring of associated gas (estimated at 2 BCM) will prevent over-depletion of Romania's remaining gas reserves. As a result, imports will increase to 7.5 BCM by 1995 after which further increases in demand will require additional imports of 3.3 BCM per annum.

Much of the growth in demand will be in the residential and commercial sectors where gas use for lighting and heating is becoming a priority. Power generation and petrochemical users will also show modest growth in gas demand while industrial use will decline as plants are closed and efficiencies increased.

H. Pricing Policy

Under the Ceausescu regime, Romanian energy prices and consumption were closely controlled by strict rationing and supply interruptions. Energy prices continue to be subject to regulation against the background of the country's shortage of energy.

There is a wide gap between international energy prices and prices for both domestically produced gas and energy product retail prices, particularly for household energy (at realistic exchange rates). In some cases, prices have even been set below cost.

Mid 1991 Prices	$/'000 m^3	$/MMBtu
Import price	93.72	2.48
Industry	57.17	1.51
Households	57.17	1.51

Source: World Bank

Prices for domestically produced gas were raised by 10 per cent in July 1991. Based on the official exchange rate of 60 lei per dollar, the price of domestically produced oil was raised to $132 per tonne, matching current prices the country pays for oil imports from the Persian Gulf and Libya.

Under the existing policy, the gas price will continue to be increased by the Government every quarter by 10 per cent, until the price reaches the international import price level. Currently, the price to industrial users is Lei 3550 ($ 57.2) per thousand Nm3, compared to the import price of $ 95 per thousand Nm3 from the Soviet Union. The gas price to household consumers is however being held constant at Lei 1000 per thousand Nm3.

There is thus a need for some form of transitional programs for gradual adjustment of energy prices to international parity levels. For tradable energies (i.e. energies for which do not have natural monopoly characteristics and for which prices are set by free interplay of supply and demand such as oil and coal), this could for example, be achieved by a system of periodic price adjustments, until prices can be set by market forces.

For non-tradable energies (energies with natural monopoly characteristics, such as natural gas and electricity), an acceptable pricing philosophy must be decided on; i.e. should they be priced on value, or on cost? If it is decided to price them on cost, the cost of providing these energies must be calculated in order to set a corresponding price. In a first step, prices could be set to cover operating costs and earn gradually increasing operating profits, thus contributing to covering capital costs, to be replaced, in the long term, by fuel-cost tariffs.

Romania is faced with a hyper-inflationary environment in the short term. The primary effect if prices are raised and wages held constant will be a rapid decline in demand, particularly in the energy sector. Gas demand, however, is less likely to be drastically reduced as it will likely be considered an essential item given its importance in the residential and commercial sectors for heating. Lower priority uses such as the petrochemical sector and certain industrial applications will take lower priority in terms of allocation of limited gas imports and as such could have lower demand in the future.

The financial difficulties of energy institutions are due to inadequate pricing, rapid build-up of accounts receivable and payable, and to a general shortage of capital. Romania needs a plan to deal with financial restructuring of the energy organizations, as well as an overall reorganization of these enterprises within the framework of an overall macroeconomic program.

I. Gas Demand Forecasts

In our low scenario we have assumed slow economic growth and limited replacement of other fuels in order to improve the environment. The high scenario assumes strong economic growth and replacement of coal-fired power generation capacity in order to reduce air pollution.

In all three scenarios we have assumed that indigenous production ceases after 1995 to reflect current R/P ratios. The emerging supply gap should, therefore, be seen as an indicator for the need for new imports as well as the need to find and develop new indigenous resources.

Romanian Gas Demand

BCM	1990	1995	2000	2005	2010	Average Growth %
Low scenario	33.2	30.5	32.0	33.4	34.6	0.2
Base Case	33.2	30.5	33.2	36.7	41.1	1.1
High scenario	33.2	31.0	35.7	43.1	51.2	2.2
Ind. Production	25.2	24.6	0	0	0	
Imports	8.0	3.0	3.0	3.0	3.0	
Deficit	0	2.9-3.4	29-32.7	30.4-40.1	31.6-48.2	

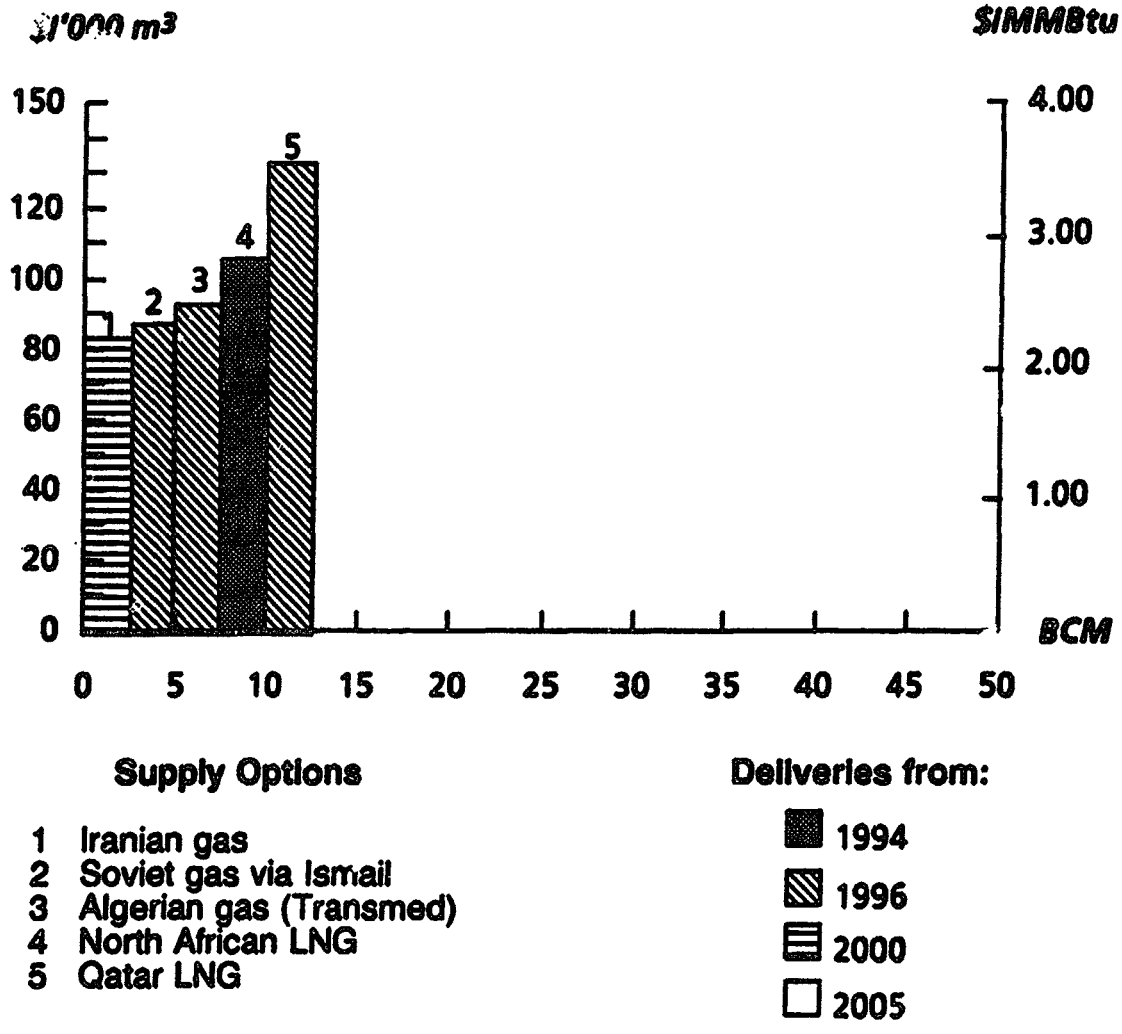
Source: Arthur D. Little

As can be seen in the table above, we foresee that a supply deficit of around 30 BCM may have developed by 2000, growing to between 30 and 50 BCM by 2010.

J. Supply Cost Curve

We have calculated the cost of bringing gas from five different supply sources to Romania. In the short to medium term, incremental Soviet gas and North African LNG are the least costly alternatives. In the long run, however, incremental Iranian gas could be delivered at lower cost than all other supply alternatives.

Supply Cost Curve for Romania: Gas Delivered Bucharest



Supply Options

1 Iranian gas
2 Soviet gas via Ismail
3 Algerian gas (Transmed)
4 North African LNG
5 Qatar LNG

Deliveries from:

- 1994
- 1996
- 2000
- 2005

Yugoslavia

A. The Yugoslavian Energy Industry - Summary

- Yugoslavia's national primary energy fuel mix in 1989 consisted of 42 per cent coal, 38 per cent oil, 13 per cent natural gas and 7 per cent nuclear and hydro electricity (Source: IEA Energy Balances).
- Natural gas has been used since before the 1960s.
- Natural gas consumption has grown at an average annual rate of 9 per cent between 1980 and 1989.
- The natural gas grid is not very well developed, consisting of two separate networks, covering only small parts in the north (Slovenia/Croatia) and east (Serbia/Bosnia-Hercegovina) of the country.
- The main problems facing the government of Yugoslavia in the energy sector are the following:
  - Need to find additional gas reserves and improve production facilities in order to maintain/increase indigenous production levels
  - Largely dependent on a single source of gas imports (USSR)
  - Aim to increase use of gas at the expense of high-polluting oil and coal consumption
  - Large need to extend transmission/distribution network in order to meet targeted increase in gas consumption
  - Need to reduce air and water pollution without impairing ability to satisfy power demand
  - Lack of financial resources required for investment
  - Need to find additional hydrocarbon reserves
  - Need to restructure the energy sectors and increase energy prices to world market price levels.

B. Historical Natural Gas Supply and Demand

Yugoslavia has estimated proven gas reserves of 82 BCM, of which two thirds are located in Croatia and one third in Vojvodina. Output from new fields (Molve, Sari and Gradec, among others) in the Podravina region have added significantly to production. Originally thought to be a good prospect, the North Adriatic has proved disappointing. Reserves at two North Adriatic fields (Ivana and Ika) are about 6.5 BCM and production is expected to reach 0.5 BCM in 1991 but only continue for about ten years.

The 6.1 BCM of gas consumption in 1989 represented 13 per cent of total energy demand versus only 8 per cent in 1980. Yugoslavia is the second smallest gas user in Eastern Europe next to Bulgaria but is planning to increase gas consumption significantly in the future. New fields have been developed (Molve), but the increase in gas use of 2.2 per cent per annum has mainly been met by imports. Domestic production has not increased as quickly as demand, causing imports to rise by an average 12 per cent per annum during 1980-89 (to 3.6 BCM).

Yugoslavian gas demand has historically been spread relatively evenly across the power generation, energy, petrochemical, industrial and residential/commercial sectors. Over time, gas use in power generation and industry has declined.

C. Gas Infrastructure

The Yugoslavian network is rather small, consisting of two systems which are not interconnected. The Serbian gas system brings imported Soviet gas from the Hungarian/Romanian border at Horgos in Vojvodina to main consumption centers in Serbia and Bosnia-Hercegovina. Approximately 1500 km of pipelines of varying diameters distribute gas to Nis, Sarajevo and Belgrade. The network mainly serves large industrial customers. Recently, Energogas resumed extension of a Soviet trunkline which will increase imports of Soviet gas transited through Bulgaria. Makpetrol of Macedonia also has plans to construct a pipeline for imports of Soviet gas through Bulgaria, which however would not be interconnected with the Energogas-pipeline.

The Northern network is used to transport Soviet gas from the Austrian border, entering the country at Maribor, to major cities in Slovenia and Croatia. INA-Naftaplan operates an underground gas storage facility at Okoli (Croatia), having a capacity of 0.35 BCM, which will rise to 0.5 BCM on completion of the second stage of development. A further 0.48 BCM gas storage facility is being built at Bantski Dvori. Others are planned in Bosnia- Hercegovina and Slovenia. A pipeline connection with the Italian transmission system at Monfalcone is presently under construction.

Yugoslavia has some indigenous gas reserves. At present, the largest field in operation is Molve, with a yearly production of 0.8 BCM. Gas has also been found in the Adriatic (Ika field), but reserves are thought to be small.

D. Major Gas Purchase Contracts

As part of an arrangement to reduce Yugoslavia's trade surplus with the USSR, new agreements have been worked out, according to which the USSR will deliver up to 12 BCM per year by 2000, which is more than double the current contract quantities. The Soviet Union will also supply pipeline equipment and engineering for development of gas networks in eastern Yugoslavia. An annual 0.6 BCM of Algerian gas, to be delivered via Italy, has been negotiated by the Slovenian company Petrol, likely to be available from the end of 1991.

E. Industry Structure

Six regional companies hold responsibility for supplying their respective supply areas with natural gas. The six companies are:

Energopetrol	Bosnia-Hercegovina
Energogas	Serbia
INA-Naftaplin	Croatia
Naftagas-Gas	Vojvodina
Makpetrol	Macedonia
Petrol	Slovenia

Only two companies are engaged in natural gas production (INA- Naftaplin and Naftagas-Gas). INA is active onshore within Croatia and offshore in the Adriatic. Naftagas only has onshore production in Vojvodina and Serbia. Import contracts are negotiated separately by all companies, without need for Federal approval.

F. Potential Contribution to Gas Environmental Improvement

The expressed objective of the Yugoslavian energy policy is the efficient supply of optimal quantities of energy at moderate cost without causing damage to the environment. Special emphasis is to be put on the reduction of pollution. Energy producers, especially power plants and coal mines, are characterized as the worst polluters. Fundamental changes to the entire energy sector are required, including a change in fuel mix for power generation, which is currently heavily dependent on coal. There is a strong environmental movement against and a moratorium preventing the development of new nuclear power. Yugoslavia has one nuclear power plant. The Government's policy is not to develop any new nuclear power before 2000. Apart from cleaning up coal-fired stations, promotion of increased use of gas in power generation seems to be the only option available if air pollution is to be reduced.

Emission control regulations requiring the use of cleaner coal have already been implemented. This will cause significant increase in costs, since neither industrial or power generation plants are fitted with adequate emission control devices. The authorities are determined to cut pollution, but it will take time, since the country has more urgent problems to be dealt with, and capital is scarce. A federal ecology tax has been discussed, but not implemented so far.

Development of the Ika gas field in the Adriatic would have the advantage of both contributing to reducing the local energy shortage and allowing a cut in pollution from fuel oil and coal burning industries and power plants in the Rijeka area. The project has however been held up by a price discussion between INA-Naftaplin and the Croatian Electricity Board.

G. Prospects for Increased Indigenous Gas Production

Yugoslavia is planning to increase indigenous gas production from the current 2.6 to more than 6 BCM by the end of the century, in order to supply the planned expansion of gas use. This may be a difficult target to realize, considering the heavy investments which would be required and the present lack of financial resources.

Since 1988, offshore exploratory operations have been carried out by foreign oil companies. Output on the Molve gas field will increase by 1 BCM per year to 1.8 BCM, due to recent addition of further gas processing installations. INA-Naftaplin is however uncertain about the prospects of finds in the northern Adriatic, and prefers to concentrate investments on the Molve gas field rather than investing offshore.

We predict that given current electricity demand, replacement of coal-fired capacity with CCGT power plants could lead to an increase in annual gas demand of between 3 and 9 BCM (depending on the amount of capacity replaced).

H. Current Plans for Expansion of Gas Markets

A major shift of policy in favor of natural gas is taking place. In general, Yugoslav gas consumption is expected to double over the next the ten years. As in many other East European countries, the shortage of funds may however force these plans to be moderated, unless foreign investors can be attracted. The increase in gas supplies is expected to come mainly from imports, primarily from the Soviet Union, but also from indigenous production.

I. Future Gas Supply and Demand

The outlook for the Yugoslavian gas sector is very positive. The Government is stressing displacement of coal and oil with gas in a wide range of industries, primarily in the power generation sector. Though official forecasts suggest a doubling of gas demand by 2000 from the 1989 level of 7.3 BCM, a more realistic estimate, taking into account capital constraints, has demand growing to 8.2 BCM in 1995 and to 10.7 BCM in 2000. With limited domestic reserves, and exploration efforts yielding only modest discoveries, most of the incremental demand will have to be satisfied by imports from a variety of new pipeline projects connecting Yugoslavia with the Soviet Union and Iran (via new links between other East European countries) and Algeria (with additional links through Italy or by means of an LNG import terminal). As of 1991, Yugoslavia is receiving gas imports from Algeria through a pipeline connection with Italy.

The driving force behind increasing gas demand in the future centers around environmental concerns and expansion of the gas distribution system. The residential/commercial and power generation sectors will grow fast, as new (Serbia, et al) and renovated (Belgrade) distribution systems and conversions of oil and gas power plant units are completed. Most of the forecast incremental gas demand in the power generation sector will be from displacement in coal and oil-fired stations. There are plans to build a gas-fired power plant in Slovenia. Other planned power stations could also be gas-fired. Growth is also significant in the transformation (including own use and losses) category given that production declines will require additional gas volumes for field use.

J. Planned Expansion of Infrastructure

The current capacity of the existing Yugoslavian network is insufficient to handle the quantities of gas which are expected to be produced locally and imported from the USSR and Algeria by 2000. Yugoslavia has very ambitious plans for the extension of its gas transmission system, which would require large investments if they were to be realized in full. Apart from construction of transmission links and distribution lines to major users all over the country,

it will be necessary to link up with the Italian, Austrian and Hungarian systems for further imports of gas from Algeria and the USSR to be possible.

An extension of the network would also provide an impetus for increased domestic production, which is planned to increase to more than 6 BCM by 2000. Construction of underground storages, which will have a total working gas capacity of 1 BCM by 2000, is underway for Croatia, Vojvodina, Slovenia and Bosnia.

In Vojvodina, where much of the indigenous gas is produced at present, domestic networks will be developed in all major residential areas. In Serbia, the USSR is helping to build a 160 km pipeline, which will bring Soviet gas transited across Romania and Bulgaria (completed end 1990?). Energogas has proposed a $160 million pipeline expansion program to be realized before 1995. It would include construction of 670 km of transmission and distribution lines and 120 km of urban networks, extending to central and southeastern parts of Serbia and Kosovo. The Belgrade gas system will be renovated with financial help in the form of soft export credits offered by the Italian government. Italgas has signed a contract to assist in the development of the Serbian gas system. There have been plans to interlink the Northern and Southern pipeline networks, but so far very little movement on this front.

The new link with the Hungarian system, which will bring in new Soviet supplies, is already under construction. The pipeline will be 600 km long, and have a capacity of 7 BCM per year. It is planned to be completed by 1992 and to supply 170 large industrial customers and 250,000 households.

K. Pricing Policy

Yugoslavia suffered hyper-inflation in 1989, with annual inflation rates reaching 2600 per cent. A market approach to energy pricing has been preferred, with attempts to increase historically low energy prices to levels which are more realistic from an international price perspective. The future of the pricing policy and the status of the Yugoslavian Dinar are affected by current political uncertainties. Yugoslavia is faced with a situation of very high inflation and, with the current political instability, could be forced to taken draconian economic corrective measures after the regional crises are resolved.

L. Gas Demand Forecasts

In our low scenario, we assume the economic recovery from the effects of the civil war to be very slow, with limited investments in environmental improvement measures, and consequently, limited displacement of fuel oil and coal. In our high scenario, we assume strong economic growth, with a gas market developing in the residential/commercial sectors in the rebuilding period from 1995 to 2000, and some replacement of fuel oil and coal fired capacity in order to reduce emissions.

Yugoslavian Gas Demand

BCM	1990	1995	2000	2005	2010	Average Growth %
Low scenario	6.9	5.9	7.8	11.3	14.9	3.9
Base Case	6.9	6.2	8.3	11.9	15.5	4.1
High scenario	6.9	6.6	9.0	13.1	17.5	4.8
Ind.. Production	2.5	1.8	2.5	2.5	2.5	
Imports	4.4	4.4	5.7	5.7	5.7	
Deficit	0	0-0.4	0-0.8	3.1-4.9	6.7-9.3	

Source: Arthur D. Little

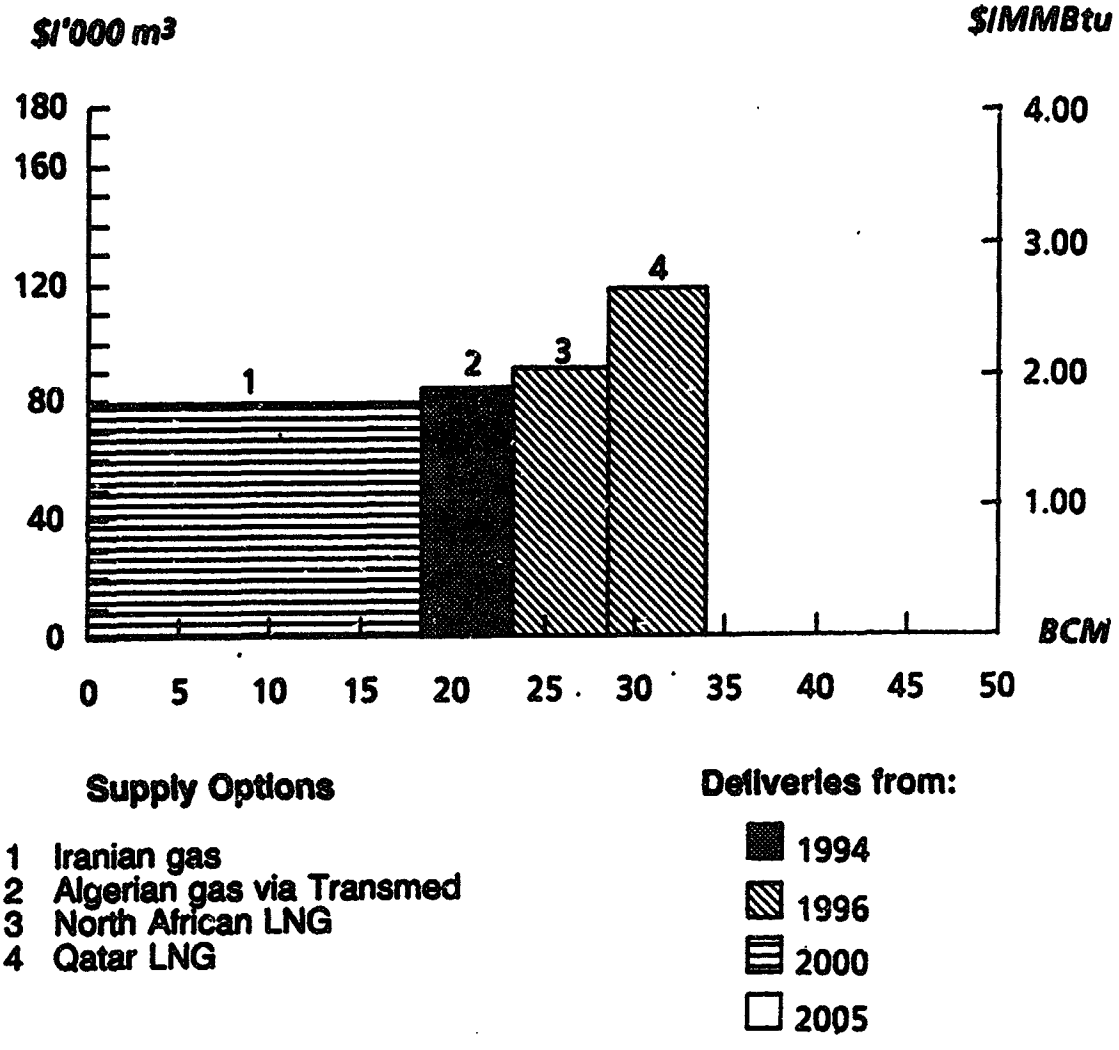
As indicated in the table, we predict that a supply deficit of up to 1 BCM may have developed by 2000, growing to between 6 and 9 BCM by 2010.

M. Supply Cost Curve

If the proposed LNG terminal in northern Yugoslavia (either at Omisalj or Koper) and the Iranian pipeline are built, Yugoslavia will have access to three relatively low cost supply sources: Algerian or Libyan LNG, Algerian pipeline gas delivered to Monfalcone, and, from 2000 onwards, Iranian gas via Bulgaria.

Incremental Soviet gas would be more costly if delivered via the new pipelines assumed in the analysis. The cost delivered Belgrade would be approximately $95 per 1000 m3 (approx. $2.50/MMBtu), which is considerably higher than Algerian gas delivered via Transmed ($84.63/1000 m3).

Supply Cost Curve for Yugoslavia: Gas Delivered Belgrade



Forecasts and Assumptions

Overview of Forecasts and Assumptions Used

Natural Demand in Eastern Europe (BCM)

	1990	2010 (Low Case)	2010 (Base Case)	2010 (High Case)
Bulgaria	6.5	7.0	7.7	17.2
Czechoslovakia	12.8	18.8	26.0	30.9
Hungary	11.3	17.1	19.4	27.7
Poland	10.1	17.1	21.2	28.3
Romania	33.2	36.6	41.1	51.2
Yugoslavia	6.9	14.9	15.5	17.5
Total	**80.8**	**109.5**	**130.9**	**172.8**

Base Case

The Base Case economic outlook for Eastern Europe as a whole is characterized by a sharp decline in economic output between the years 1990 to 1995, as industries close and the economy restructures, a period of declining to very slow growth. From 1995 to 2000, as countries adapt to market economic conditions, typical GDP growth rates have been assumed to be 0.5 to 1.5 per cent per annum. We have assumed the period from 2000 to 2010 to be one characterized by higher growth rates, typically 2 to 3.5 per cent per annum of GDP growth as the free market takes hold.

Energy growth will be characterized to some extent by the wish to move away from oil and solid fuels towards natural gas. Consequently, gas demand is forecast to fall by only 0.3 per cent per annum during the difficult period to 1995, during which time its overall market share may increase to up to 30 per cent.

The residential sector is the only sector which is forecast to experience growth to 1995, driven by the increased availability of gas which is planned for several major cities which currently suffer from air pollution caused by the use of lignite and other solid fuels in the home. The residential sector is forecast to experience much higher growth rates than other sectors, reflecting the pattern experienced in many of the West European economies, notably the UK, Netherlands and Germany, during the 1970s.

Industrial energy demand is forecast to suffer the greatest reduction during the period to 1995, reflected by a drop in industrial gas demand of 1 per cent per annum. From 1995 to 2000, industry may recover, with a resurgence in heavy industry, now fueled by natural gas rather than by solid fuels. Lighter industries will begin to emerge also during this period, although at a slower rate. The basis for this assumption is that Eastern Europe may be better placed to operate the heavier, energy intensive, mature technology type industries than its Western neighbors, as labor costs are expected to remain well below Western equivalents. Similarly, Eastern Europe may, due to lack of technological/commercial know-how and real competitive advantage, not be able to develop significant alternative industries in the service/high technology sectors within the time frame of this forecast.

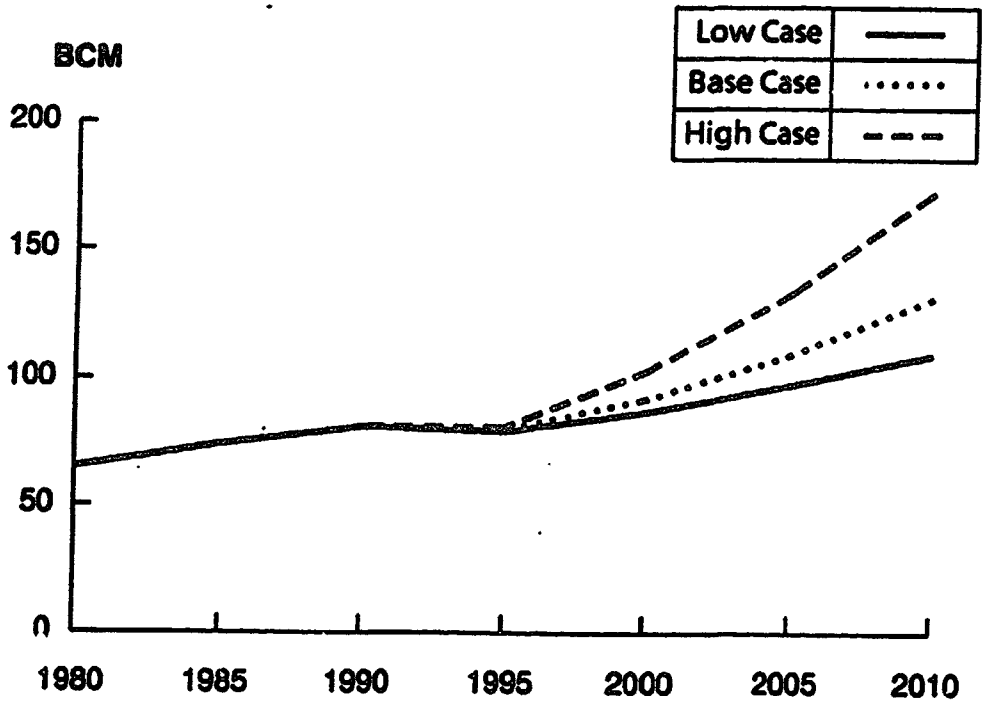
The use of gas in the power generation sector is expected to increase most sharply in the period 1995 to 2000, as existing solid fuel based district heating systems are switched to natural gas, and as highly efficient stand alone systems begin to be constructed, a trend which is expected to continue throughout the period.

The methodology employed to describe natural gas supply is based on current plans, existing contracts and reserve/production ratios. The supply forecasts are identical for the base, low, and high cases, which allows consistent comparison of the relative supply gap for each case. The outlook may be used to identify the implications of demand forecasts on required investment in production capability or imported gas. It does not, however, provide a view on how gas supplies might develop, and should thus not be treated as a supply forecast (for example, we expect Romania to continue to produce indigenous natural gas throughout the forecast period, despite the low reserve production ratio, with production ceasing in our outlook in 2000 rather than as per R/P ratio, in the early 1990s).

The High Gas Case and the Low Gas Case

The High and Low cases represent sensitivities on the Base Case forecast, indicating the range of uncertainty within which forecasts must be viewed. The economic outlook features correspondingly higher/lower growth, which is reflected in overall energy demand and natural gas demand.

Natural Gas Demand Outlook for Eastern Europe [a.]



a. Includes Bulgaria, Czechoslovakia, Hungary, Poland, Romania and Yugoslavia

The difference between Low Case gas demand and Base Case gas demand in 2010 is shown to be 21.5 BCM, which is approximately 50 per cent of the difference between the High Case and the Base Case, at 41.8 per cent. This reflects a combination of two effects, the likelihood that the sharp economic and energy-use decline in the early 1990s will impact fuels other than gas, and that new energy demand may be satisfied by increased use of natural gas. The elasticity of natural gas to energy demand is low during times of recession, as transmission and distribution infrastructure which is already in place is not likely to be underutilized. The elasticity may be considerably higher in times of economic and energy-use growth, fueled by the desire to improve living standards in the residential sector, and to increase efficiency and reduce environmental damage in other sectors.

Case assumptions vary considerably by country. For example, natural gas use in Bulgaria, which is not expected to develop its gas network significantly, features very low Low Case and Base Case Growth, but very high High Case growth. This reflects the low level of gas use planned by the government, and the high potential for gas development should the Pannonian basin prove to be gas-prone. The Yugoslavian outlook, on the other hand, features all three cases with gas use in 2000 at two to three times the 1990 level, reflecting the existing "gas culture" and the strong likelihood of a natural gas based energy future.

Bulgaria

Unlike most of Eastern Europe, Bulgaria plans to base its energy future mainly on the introduction of clean coal technology and continued development of indigenous solid fuel reserves.

The Low and Base Case demand scenarios each depict an energy future where existing gas infrastructure is upgraded and better utilized, but not expanded significantly. The High Case assumes that the Government reverses its decision to limit future gas imports from the USSR, connects to the Western European gas network and develops indigenous gas reserves which, though currently low, have the potential to increase rapidly following exploration by Western companies in previously unexplored areas. Indigenous gas could thus be used to displace oil consumption and give gas a share of the overall energy market roughly corresponding to that held by solid fuels. The high gas case also features the development of a residential gas market around the turn of the century.

The wide range between Base Case and High Case gas demand illustrates the level of uncertainty which remains about Bulgaria. About half of Bulgaria's natural gas consumption is currently used in the chemicals industry, which may decline, leaving spare pipeline capacity to service any new industries requiring natural gas. On the other hand, the pipeline which transports Soviet gas to Greece, which is believed to have up to 50 per cent spare capacity available, could initiate the development of an integrated network across Bulgaria.

Czechoslovakia

Natural gas demand in Czechoslovakia is forecast to increase from 12.8 BCM in 1990 to between 18.8 and 30.9 BCM by 2010. From a relatively slow start during the period 1990 to 1995, when demand growth is forecast at 1.4 per cent per annum, natural gas is expected rapidly to displace lignite, particularly in the heavily polluted major cities. Up to 7.2 BCM (low calorific value) town gas may be replaced with natural gas by 2000, and there are plans to replace 168 coal-based CHP heating units in the same time period.

Our gas forecasts are consistent with government plans to increase gas use to 25 BCM by 2010. The IEA statistics do not identify separately gas use by the commercial sector in Czechoslovakia, or any other East European country. Other sources identify approximately half of the gas use of the IEA's "Residential Sector" as belonging to the "Commercial Sector".

Energy pricing in Czechoslovakia features, by Western standards, relatively high gas prices and very low solid fuel prices to both industry and the residential sector. Solid fuel prices may increase up to 500 per cent by 1995 from January 1991 levels, depending on what level of income is socially achievable by the Government. Hence the relative price of gas against its major competitor is expected to improve substantially, again supporting the outlook for increased gas demand.

Hungary

Hungarian gas demand is forecast to increase from 11.3 BCM in 1990 to between 17.1 and 27.7 BCM by 2010. The Base Case forecast of 19.4 BCM by 2010 reflects the view that cheap imported coal may displace very poor quality indigenous coal, giving natural gas a relatively modest increase in market share.

The Base Case also reflects the impact of the Government's planned "flexibility factor", whereby energy demand is forecast to rise at 30 - 40 per cent of the rate of increase in national income. The plan may prove to be too ambitious, but its impact should not be discounted, given the Hungarian interest in energy efficiency and, by East European standards, strong tradition of looking West for new ideas and innovation.

The rate of new connections in the residential sector is expected to be slow during the period 1990 - 1995, at 14 per cent per annum. The rate of connection is likely to pick up again once the shock impact of market pricing has worn off. The rate of connection is unlikely to reach the 12 per cent per annum which was typical of the 1980s, as the grid will become much larger, but the smaller percentage increases represent an increasing number of actual connections per annum.

Hungary may begin to build gas fired power generation capability from 2000 to meet surging demand for electricity. The period before 2000 may see more coal to gas displacement.

Poland

Increased use of natural gas in Poland will occur most strongly in the residential sector, progressively displacing indigenous coal, and representing an increase from 2.9 BCM in 1990 to between 7.7 and 17.0 in 2010. The wide gap between Low and High case highlights the Polish dilemma about coal, which currently dominates the primary energy mix, representing 78 per cent of total primary energy demand in 1989.

The environmental pressure to move towards gas in cities, to address the serious air pollution problems, and to diversify away from coal is balanced by social pressure to protect the coal industry, which is likely to suffer from sharply reduced demand both at home and abroad. Other sectors may experience more modest growth in gas demand, with the key uncertainty being the availability of indigenous gas. Poland has ambitious plans to develop coal-bed methane, which, if successful, may lead to gas increasing its market share in all sectors.

Romania

Representing 45 per cent of primary energy demand in 1989, the use of gas dominates Romanian energy. 1990 demand of 33.2 BCM is forecast to rise to between 36.6 and 51.2 BCM by 2010. The low gas demand case represents little development of the gas network, the existence of which is the key factor which may prevent a sustained reduction in gas use.

The Romanian energy outlook is complex. There is considerable waste of energy in the industry and power generation sectors, where gas demand may be reduced by up to 25 per cent through the implementation of basic conservation measures. Underlying this, there is considerable unsatisfied demand in the residential, commercial and industrial power generation sectors, which all have been subject to rationing and supply cuts during the 1980s and 1990s.

The supply side gives little firm indication about the way in which energy will be used in the future. Oil, which is relatively abundantly available, is too valuable to be used to satisfy indigenous demand, as it is the main source of export revenue. There are limited indigenous coal reserves, and the mainstay of energy demand has traditionally been indigenous gas. Gas has been over-produced and sold cheaply to feed highly energy intensive industries. The current reserves to production ratio indicates that gas reserves will run out in the early 1990s.

The forecasts are based on the view that energy demand will reduce by up to 30 per cent per annum in the period 1990 to 1995, and that this will be reflected in a reduction in gas demand of up to 17.7 per cent per annum. Being driven by supply rather than economic growth, we expect gas to continue to dominate the Romanian energy balance, fed mainly by gas from new discoveries, but also by continued imports from traditional supply sources.

The development of the residential sector is subject to the greatest uncertainty, with demand estimates in 2010 ranging between 2 and 11 BCM. There is a considerable latent demand for heating and hot water, and an existing transmission network which could take gas to the centers of demand. The cost of further development of the distribution network, and the ability of consumers to pay for gas supplies are, however, serious barriers to the development of a residential gas market.

Yugoslavia

Natural gas demand in Yugoslavia is forecast to increase from 6.9 BCM in 1990 to between 14.9 and 17.5 BCM by 2010. This is based on the assumption that the current political difficulties are resolved permanently during the period 1990 - 1995. For the purpose of this forecast, we have treated Yugoslavia as one country, despite the fact that each region may pursue separate, rather than joint, policies in the future.

Industrial demand features an average decline of 6.4 per cent per annum over the period 1990 to 1995, which represents a very sharp decline in 1992/93 and a steady recovery thereafter, displacing coal.

The residential sector features the highest growth, with a Base Case growth rate of 10 per cent per annum between 1995 and 2000. This reflects the small size of the sector at present, and ambitious plans to connect Serbian homes to the gas network in order to reduce air pollution.

Gas use in power generation is expected to approximately double over the time frame, as existing coal fired capacity is refitted to burn gas to combat air pollution. No gas fired CCGT generation capacity is planned. Overall, Yugoslavian gas demand as a share of primary energy demand was 13 per cent in 1989, expected in the context of this forecast to increase to around 20 per cent by 2010.

THE WORLD BANK SEMINAR

Natural Gas in Eastern Europe Regional
Issues and Options

London, January 16-17, 1992

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The Rt. Hon. John Wakeham MP, Secretary of State for Energy, United Kingdom

Mr. W. Wapenhans, Vice President, World Bank
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	Ms. V. Hristova-Achoundova Chief of Department Ministry of Industry and Trade
	Mr. A. Popov President, Bulgargaz
Czech Slovak Federal Republic (CSFR)	Mr. V. Ludvik Director, Federal Distribution Grid Federal Ministry of Economy
	Mrs. Ptackova C.P.P.
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Poland	Mr. K. Adamczyk General Director Energy and Fuel Management Department Ministry of Industry and Trade
	Mr. M. Kaczmarczyk General Manager PGNG
	Mr. A. Findzinski Director for Gas Industry PGNG
	Mr. A. Brach Economic Director PGNG
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	Mr. N. Pavlovski Director Romgaz
	Mrs. M. Neicu Counsellor Ministry of Industry
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	Mr. H. Mefti Chairman Conseil d'Administration du Fonds de Participation
Iran	Mr. A. Moshtaghian Director Exploration and Production NIOC

The Netherlands	Mr. R. Bemer Director of Gas Policy Ministry of Economics Affairs
	Mr. G. H. B. Verberg Commercial Managing Director Gasunie
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	Mr. E. H. M. Price Chief Economic Adviser Department of Energy
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	Mr. G. Hedley - IFC
Presentation	J. P. Morgan & Co. Mr. S. C. Chugh, Managing Director
Consultants	Arthur D. Little (U.K.) Mr. J. C. Wood-Collins, Vice President Mr. N. White, Senior Consultant
	Gas Strategies (U.K.) Mr. J. Ball, Mr. J. Stern

ENERGY SECTOR MANAGEMENT ASSISTANCE PROGRAMME

COMPLETED ACTIVITIES

Country	*Activity*	*Date*	*Number*
	SUB-SAHARAN AFRICA (AFR)		
Africa Regional	Anglophone Africa Household Energy Workshop (English)	07/88	085/88
	Regional Power Seminar on Reducing Electric Power System Losses in Africa (English)	08/88	087/88
	Institutional Evaluation of EGL (English)	02/89	098/89
	Biomass Mapping Regional Workshops (English - Out of Print)	05/89	--
	Francophone Household Energy Workshop (French)	08/89	103/89
	Interafrican Electrical Engineering College: Proposals for Short- and Long-Term Development (English)	03/90	112/90
	Biomass Assessment and Mapping (English - Out of Print)	03/90	--
Angola	Energy Assessment (English and Portuguese)	05/89	4708-ANG
	Power Rehabilitation and Technical Assistance (English)	10/91	142/91
Benin	Energy Assessment (English and French)	06/85	5222-BEN
Botswana	Energy Assessment (English)	09/84	4998-BT
	Pump Electrification Prefeasibility Study (English)	01/86	047/86
	Review of Electricity Service Connection Policy (English)	07/87	071/87
	Tuli Block Farms Electrification Study (English)	07/87	072/87
	Household Energy Issues Study (English - Out of Print)	02/88	--
	Urban Household Energy Strategy Study (English)	05/91	132/91
Burkina Faso	Energy Assessment (English and French)	01/86	5730-BUR
	Technical Assistance Program (English)	03/86	052/86
	Urban Household Energy Strategy Study (English and French)	06/91	134/91
Burundi	Energy Assessment (English)	06/82	3778-BU
	Petroleum Supply Management (English)	01/84	012/84
	Status Report (English and French)	02/84	011/84
	Presentation of Energy Projects for the Fourth Five-Year Plan (1983-1987) (English and French)	05/85	036/85
	Improved Charcoal Cookstove Strategy (English and French)	09/85	042/85
	Peat Utilization Project (English)	11/85	046/85
	Energy Assessment (English and French)	01/92	9215-BU
Cape Verde	Energy Assessment (English and Portuguese)	08/84	5073-CV
	Household Energy Strategy Study (English)	02/90	110/90
Central African Republic	Energy Assessement (French)	08/92	9898-CAR
Comoros	Energy Assessment (English and French)	01/88	7104-COM
Congo	Energy Assessment (English)	01/88	6420-COB
	Power Development Plan (English and French)	03/90	106/90
Côte d'Ivoire	Energy Assessment (English and French)	04/85	5250-IVC
	Improved Biomass Utilization (English and French)	04/87	069/87
	Power System Efficiency Study (Out of Print)	12/87	--
	Power Sector Efficiency Study (French)	02/92	140/91
Ethiopia	Energy Assessment (English)	07/84	4741-ET
	Power System Efficiency Study (English)	10/85	045/85
	Agricultural Residue Briquetting Pilot Project (English)	12/86	062/86

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	Bagasse Study (English)	12/86	063/86
	Cooking Efficiency Project (English)	12/87	--
Gabon	Energy Assessment (English)	07/88	6915-GA
The Gambia	Energy Assessment (English)	11/83	4743-GM
	Solar Water Heating Retrofit Project (English)	02/85	030/85
	Solar Photovoltaic Applications (English)	03/85	032/85
	Petroleum Supply Management Assistance (English)	04/85	035/85
Ghana	Energy Assessment (English)	11/86	6234-GH
	Energy Rationalization in the Industrial Sector (English)	06/88	084/88
	Sawmill Residues Utilization Study (English)	11/88	074/87
Guinea	Energy Assessment (Out of Print)	11/86	6137-GUI
Guinea-Bissau	Energy Assessment (English and Portuguese)	08/84	5083-GUB
	Recommended Technical Assistance Projects (English & Portuguese)	04/85	033/85
	Management Options for the Electric Power and Water Supply Subsectors (English)	02/90	100/90
	Power and Water Institutional Restructuring (French)	04/91	118/91
Kenya	Energy Assessment (English)	05/82	3800-KE
	Power System Efficiency Study (English)	03/84	014/84
	Status Report (English)	05/84	016/84
	Coal Conversion Action Plan (English - Out of Print)	02/87	--
	Solar Water Heating Study (English)	02/87	066/87
	Peri-Urban Woodfuel Development (English)	10/87	076/87
	Power Master Plan (English - Out of Print)	11/87	--
Lesotho	Energy Assessment (English)	01/84	4676-LSO
Liberia	Energy Assessment (English)	12/84	5279-LBR
	Recommended Technical Assistance Projects (English)	06/85	038/85
	Power System Efficiency Study (English)	12/87	081/87
Madagascar	Energy Assessment (English)	01/87	5700-MAG
	Power System Efficiency Study (English and French)	12/87	075/87
Malawi	Energy Assessment (English)	08/82	3903-MAL
	Technical Assistance to Improve the Efficiency of Fuelwood Use in the Tobacco Industry (English)	11/83	009/83
	Status Report (English)	01/84	013/84
Mali	Energy Assessment (English and French)	11/91	8423-MLI
	Household Energy Strategy (English and French)	03/92	147/92
Islamic Republic of Mauritania	Energy Assessment (English and French)	04/85	5224-MAU
	Household Energy Strategy Study (English and French)	07/90	123/90
Mauritius	Energy Assessment (English)	12/81	3510-MAS
	Status Report (English)	10/83	008/83
	Power System Efficiency Audit (English)	05/87	070/87
	Bagasse Power Potential (English)	10/87	077/87
Mozambique	Energy Assessment (English)	01/87	6128-MOZ
	Household Electricity Utilization Study (English)	03/90	113/90
Niger	Energy Assessment (French)	05/84	4642-NIR
	Status Report (English and French)	02/86	051/86
	Improved Stoves Project (English and French)	12/87	080/87

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Niger	Household Energy Conservation and Substitution (English and French)	01/88	082/88
Nigeria	Energy Assessment (English)	08/83	4440-UNI
Rwanda	Energy Assessment (English)	06/82	3779-RW
	Energy Assessment (English and French)	07/91	8017-RW
	Status Report (English and French)	05/84	017/84
	Improved Charcoal Cookstove Strategy (English and French)	08/86	059/86
	Improved Charcoal Production Techniques (English and French)	02/87	065/87
	Commercialization of Improved Charcoal Stoves and Carbonization Techniques Mid-Term Progress Report (English and French)	12/91	141/91
SADCC	SADCC Regional Sector: Regional Capacity-Building Program for Energy Surveys and Policy Analysis (English)	11/91	--
Sao Tome and Principe	Energy Assessment (English)	10/85	5803-STP
Senegal	Energy Assessment (English)	07/83	4182-SE
	Status Report (English and French)	10/84	025/84
	Industrial Energy Conservation Study (English)	05/85	037/85
	Preparatory Assistance for Donor Meeting (English and French)	04/86	056/86
	Urban Household Energy Strategy (English)	02/89	096/89
Seychelles	Energy Assessment (English)	01/84	4693-SEY
	Electric Power System Efficiency Study (English)	08/84	021/84
Sierra Leone	Energy Assessment (English)	10/87	6597-SL
Somalia	Energy Assessment (English)	12/85	5796-SO
Sudan	Management Assistance to the Ministry of Energy and Mining	05/83	003/83
	Energy Assessment (English)	07/83	4511-SU
	Power System Efficiency Study (English)	06/84	018/84
	Status Report (English)	11/84	026/84
	Wood Energy/Forestry Feasibility (English - Out of Print)	07/87	073/87
Swaziland	Energy Assessment (English)	02/87	6262-SW
Tanzania	Energy Assessment (English)	11/84	4969-TA
	Peri-Urban Woodfuels Feasibility Study (English)	08/88	086/88
	Tobacco Curing Efficiency Study (English)	05/89	102/89
	Remote Sensing and Mapping of Woodlands (English)	06/90	--
	Industrial Energy Efficiency Technical Assistance (English - Out of Print)	08/90	122/90
Togo	Energy Assessment (English)	06/85	5221-TO
	Wood Recovery in the Nangbeto Lake (English and French)	04/86	055/86
	Power Efficiency Improvement (English and French)	12/87	078/87
Uganda	Energy Assessment (English)	07/83	4453-UG
	Status Report (English)	08/84	020/84
	Institutional Review of the Energy Sector (English)	01/85	029/85
	Energy Efficiency in Tobacco Curing Industry (English)	02/86	049/86
	Fuelwood/Forestry Feasibility Study (English)	03/86	053/86
	Power System Efficiency Study (English)	12/88	092/88
	Energy Efficiency Improvement in the Brick and Tile Industry (English)	02/89	097/89
	Tobacco Curing Pilot Project (English - Out of Print)	03/89	UNDP Terminal Report

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Zaire	Energy Assessment (English)	05/86	5837-ZR
Zambia	Energy Assessment (English)	01/83	4110-ZA
	Status Report (English)	08/85	039/85
	Energy Sector Institutional Review (English)	11/86	060/86
Zambia	Power Subsector Efficiency Study (English)	02/89	093/88
	Energy Strategy Study (English)	02/89	094/88
	Urban Household Energy Strategy Study (English)	08/90	121/90
Zimbabwe	Energy Assessment (English)	06/82	3765-ZIM
	Power System Efficiency Study (English)	06/83	005/83
	Status Report (English)	08/84	019/84
	Power Sector Management Assistance Project (English)	04/85	034/85
	Petroleum Management Assistance (English)	12/89	109/89
	Power Sector Management Institution Building (English - Out of Print)	09/89	--
	Charcoal Utilization Prefeasibility Study (English)	06/90	119/90
	Integrated Energy Strategy Evaluation (English)	01/92	8768-ZIM

EAST ASIA AND PACIFIC (EAP)

Asia Regional	Pacific Household and Rural Energy Seminar (English)	11/90	--
China	County-Level Rural Energy Assessments (English)	05/89	101/89
	Fuelwood Forestry Preinvestment Study (English)	12/89	105/89
Fiji	Energy Assessment (English)	06/83	4462-FIJ
Indonesia	Energy Assessment (English)	11/81	3543-IND
	Status Report (English)	09/84	022/84
	Power Generation Efficiency Study (English)	02/86	050/86
	Energy Efficiency in the Brick, Tile and Lime Industries (English)	04/87	067/87
	Diesel Generating Plant Efficiency Study (English)	12/88	095/88
	Urban Household Energy Strategy Study (English)	02/90	107/90
	Biomass Gasifier Preinvestment Study Vols. I & II (English)	12/90	124/90
Malaysia	Sabah Power System Efficiency Study (English)	03/87	068/87
	Gas Utilization Study (English)	09/91	9645-MA
Myanmar	Energy Assessment (English)	06/85	5416-BA
Papua New Guinea	Energy Assessment (English)	06/82	3882-PNG
	Status Report (English)	07/83	006/83
	Energy Strategy Paper (English - Out of Print)	--	--
	Institutional Review in the Energy Sector (English)	10/84	023/84
	Power Tariff Study (English)	10/84	024/84
Solomon Islands	Energy Assessment (English)	06/83	4404-SOL
	Energy Assessment (English)	01/92	979/SOL
South Pacific	Petroleum Transport in the South Pacific (English-Out of Print)	05/86	--
Thailand	Energy Assessment (English)	09/85	5793-TH
	Rural Energy Issues and Options (English - Out of Print)	09/85	044/85
	Accelerated Dissemination of Improved Stoves and Charcoal Kilns (English - Out of Print)	09/87	079/87

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Thailand	Northeast Region Village Forestry and Woodfuels Preinvestment Study (English)	02/88	083/88
	Impact of Lower Oil Prices (English)	08/88	--
	Coal Development and Utilization Study (English)	10/89	--
Tonga	Energy Assessment (English)	06/85	5498-TON
Vanuatu	Energy Assessment (English)	06/85	5577-VA
Western Samoa	Energy Assessment (English)	06/85	5497-WSO
	SOUTH ASIA (SAS)		
Bangladesh	Energy Assessment (English)	10/82	3873-BD
	Priority Investment Program	05/83	002/83
	Status Report (English)	04/84	015/84
	Power System Efficiency Study (English)	02/85	031/85
	Small Scale Uses of Gas Prefeasibility Study (English - (Out of Print)	12/88	--
India	Opportunities for Commercialization of Nonconventional Energy Systems (English)	11/88	091/88
	Maharashtra Bagasse Energy Efficiency Project (English)	05/91	120/91
	Mini-Hydro Development on Irrigation Dams and Canal Drops Vols. I, II and III (English)	07/91	139/91
Nepal	Energy Assessment (English)	08/83	4474-NEP
	Status Report (English)	01/85	028/84
Pakistan	Household Energy Assessment (English - Out of Print)	05/88	--
	Assessment of Photovoltaic Programs, Applications, and Markets (English)	10/89	103/89
Sri Lanka	Energy Assessment (English)	05/82	3792-CE
	Power System Loss Reduction Study (English)	07/83	007/83
	Status Report (English)	01/84	010/84
	Industrial Energy Conservation Study (English)	03/86	054/86
	EUROPE AND CENTRAL ASIA (ECA)		
Eastern Europe	The Future of Natural Gas in Eastern Europe (English)	08/92	149/92
Portugal	Energy Assessment (English)	04/84	4824-PO
Turkey	Energy Assessment (English)	03/85	3877-TU
	MIDDLE EAST AND NORTH AFRICA (MNA)		
Morocco	Energy Assessment (English and French)	03/84	4157-MOR
	Status Report (English and French)	01/86	048/86
Syria	Energy Assessment (English)	05/86	5822-SYR
	Electric Power Efficiency Study (English)	09/88	089/88
	Energy Efficiency Improvement in the Cement Sector (English)	04/89	099/89
	Energy Efficiency Improvement in the Fertilizer Sector(English)	06/90	115/90

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Tunisia	Fuel Substitution (English and French)	03/90	--
	Power Efficiency Study (English and French)	02/92	136/91
	Energy Management Strategy in the Residential and Tertiary Sectors (English)	04/92	146/92
Yemen	Energy Assessment (English)	12/84	4892-YAR
	Energy Investment Priorities (English - Out of Print)	02/87	6376-YAR
	Household Energy Strategy Study Phase I (English)	03/91	126/91
	LATIN AMERICA AND THE CARIBBEAN (LAC)		
LAC Regional	Regional Seminar on Electric Power System Loss Reduction in the Caribbean (English)	07/89	--
Bolivia	Energy Assessment (English)	04/83	4213-BO
	National Energy Plan (English)	12/87	--
	National Energy Plan (Spanish)	08/91	131/91
	La Paz Private Power Technical Assistance (English)	11/90	111/90
	Natural Gas Distribution: Economics and Regulation (English)	03/92	125/92
	Prefeasibility Evaluation Rural Electrification and Demand Assessment (English and Spanish)	04/91	129/91
	Private Power Generation and Transmission (English)	01/92	137/91
Chile	Energy Sector Review (English - Out of Print)	08/88	7129-CH
Colombia	Energy Strategy Paper (English)	12/86	--
Costa Rica	Energy Assessment (English and Spanish)	01/84	4655-CR
	Recommended Technical Assistance Projects (English)	11/84	027/84
	Forest Residues Utilization Study (English and Spanish)	02/90	108/90
Dominican Republic	Energy Assessment (English)	05/91	8234-DO
Ecuador	Energy Assessment (Spanish)	12/85	5865-EC
	Energy Strategy Phase I (Spanish)	07/88	--
	Energy Strategy (English)	04/91	--
Haiti	Energy Assessment (English and French)	06/82	3672-HA
	Status Report (English and French)	08/85	041/85
	Household Energy Strategy (English and French)	12/91	143/91
Honduras	Energy Assessment (English)	08/87	6476-HO
	Petroleum Supply Management (English)	03/91	128/91
Jamaica	Energy Assessment (English)	04/85	5466-JM
	Petroleum Procurement, Refining, and Distribution Study (English)	11/86	061/86
	Energy Efficiency Building Code Phase I (English-Out of Print)	03/88	--
	Energy Efficiency Standards and Labels Phase I (English - Out of Print)	03/88	--
	Management Information System Phase I (English - Out of PRint)	03/88	--
	Charcoal Production Project (English)	09/88	090/88
	FIDCO Sawmill Residues Utilization Study (English)	09/88	088/88
	Energy Sector Strategy and Investment Planning Study (English)	07/92	135/92

Country	*Activity*	*Date*	*Number*
Mexico	Improved Charcoal Production Within Forest Management for the State of Veracruz (English and Spanish)	08/91	138/91
Panama	Power System Efficiency Study (English - Out of Print)	06/83	004/83
Paraguay	Energy Assessment (English)	10/84	5145-PA
	Recommended Technical Assistance Projects (English-(Out of Print)	09/85	--
	Status Report (English and Spanish)	09/85	043/85
Peru	Energy Assessment (English)	01/84	4677-PE
	Status Report (English - Out of Print)	08/85	040/85
	Proposal for a Stove Dissemination Program in the Sierra (English and Spanish)	02/87	064/87
	Energy Strategy (Spanish)	12/90	--
Saint Lucia	Energy Assessment (English)	09/84	5111-SLU
St. Vincent and the Grenadines	Energy Assessment (English)	09/84	5103-STV
Trinidad and Tobago	Energy Assessment (English - Out of Print)	12/85	5930-TR

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Energy End Use Efficiency: Research and Strategy (English - Out of Print)	11/89	--
Guidelines for Utility Customer Management and Metering (English and Spanish)	07/91	--
Women and Energy--A Resource Guide The International Network: Policies and Experience (English)	04/90	--
Assessment of Personal Computer Models for Energy Planning in Developing Countries (English)	10/91	--