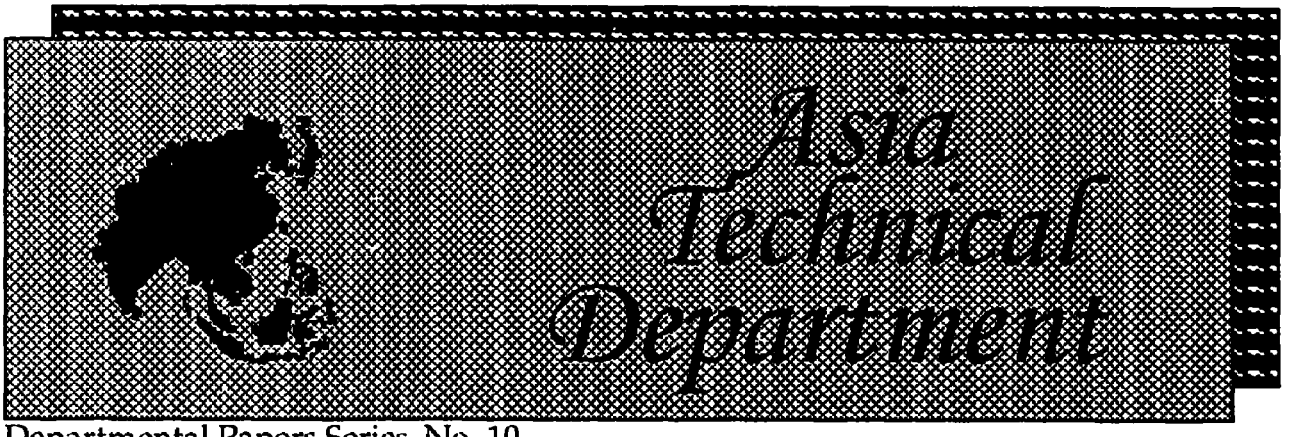

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SOUTH ASIA GAS TRADE

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FOREWORD

Energy is crucial for sustained growth of the economies in South Asia. Although India, Pakistan and Bangladesh possess substantial hydrocarbon reserves in one form or another, their size and production rate are too small to supply all the energy that is needed in these countries. Because natural gas as a fuel has properties which are advantageous in terms of efficiency and environmental impact compared to such other fuels as oil and coal, the Governments of India and Pakistan have explored the possibilities to import natural gas in addition to their domestic gas production.

Various Memoranda of Understanding have been signed recently between the Governments of India and Pakistan and several private sector consortia on the development of ambitious LNG or gas pipeline import schemes, based upon the gas reserves in the Middle East. Countries like Qatar, Iran, Oman, the UAE and Yemen have substantial reserves of natural gas and are in principle candidates to supply India and/or Pakistan. Bangladesh is a potential gas supplier for India. Several feasibility studies for gas import projects have been completed or are underway, all of them based on a specific set of assumptions that makes mutual comparisons difficult. The need was felt to have a broad overview of possible gas trade projects, based on a consistent set of assumptions, and of other issues relevant for successful implementation of such projects. The paper is meant to provide an overall understanding of gas trade issues for India, Pakistan and Bangladesh.

The views and interpretations set forth in the paper are those of the authors. However, it is hoped that disseminating this information among the Bank staff advising borrower governments on gas trade issues will lead them to bring this analysis and recommendations to the attention of Asian decision makers, and thus to bolster the effectiveness of the Bank's operations in the region.

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ABBREVIATIONS AND ACRONYMS

mmcfd	million cubic feet per day
bcf	billion (=1000 million) cubic feet
tcf	trillion (=1000 billion) cubic feet
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
kWh	kilowatt hours
TWh	terawatt (=billion kilowatt) hours
MW	megawatt
mmtoe	million tonnes of oil equivalent
mmtce	million tonnes of coal equivalent
Btu	British thermal unit
mmBtu	million British thermal units
bcm	billion cubic meters
GDP	Gross Domestic Product
CIF	Costs, Insurance and Freight (included)
ESMAP	Energy Sector Management Assistance Program
p.a.	per annum

Executive Summary

Gas Trade in South Asia

The world recognizes natural gas as a premium fuel, both for environmental and economic reasons. In Bangladesh, natural gas is in abundance (estimated reserves of 12 tcf) and is almost the only domestic fuel, supplying 74 percent of the demand for commercial energy. While it has potential for gas exports, the extent would depend on the new discoveries to be made. India has substantial gas reserves (26 tcf) but has been importing petroleum and petroleum products in ever rising quantities as the demand/supply gap for commercial energy keeps widening. Pakistan's gas reserves are estimated at 23 tcf, but its oil and coal reserves are limited and the hydropower resources are difficult to develop. Pakistan too has been importing petroleum and petroleum in rising volumes as the demand for commercial energy has been running ahead of a slower paced but growing domestic supply including new gas.

A number of studies[1] have been carried out to analyze the issues involved in meeting the growing gap between commercial energy supply and demand in the subcontinent. The objective of this note is to review the existing data, develop a framework for the analysis of the various options and to recommend a course of action for the future.

Based on commercial energy demand projections for India, it is expected that the total commercial energy demand would be about 375 million tonnes of oil equivalent (mmtoe) by the year 2003 from the 1994 level of 246 mmtoe, an increase of 52 percent.[2] Based on the present plans of the domestic agencies, the domestic supply of commercial energy is projected to grow at an average of 4.2 percent p.a., leaving a sizable energy deficit of nearly 70 mmtoe - against today prices valued at about US$7.0 billion - in 2003, as shown in the table below:

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[1]Two studies, one an ESMAP assessment of Pakistan's natural gas potential with a recommended strategy for import of gas, and the other a review of the Indian natural gas market undertaken by consultants contain a wealth of data which is drawn on for this paper. A report under preparation in ASTDR titled "Energy Perspectives aned Power investments in the Next Ten Years" is also relied on for additional data, as well as petroleum intelligence reports.

[2]These projections are based on a GDP growth rate of 5 percent p.a. during this period.

Energy demand and supply in India 1999-2003

Year	Total energy demand mmtoe	Domestic supply: Coal mmtce*	Coal mmtoe	Oil mmtoe	Hydro TWH	Hydro mmtoe**	Natural Gas bcf	Natural Gas mmtoe	Total energy supply mmtoe	Demand/ supply gap mmtoe
1993	246	191	134	30	102	36	517	13	214	32
1999	318	253	177	41	98	34	955	24	276	42
2000	332	266	186	40	102	36	955	24	285	47
2001	346	276	193	38	106	37	955	24	292	54
2002	365	287	201	36	110	38	955	24	299	66
2003	374	299	209	33	113	39	955	24	305	69

* mmtce=0.7 mmtoe

** Estimate based on a 25 percent efficiency of equivalent oil fired plant.

A similar evaluation in Pakistan leads to a projection of total commercial energy demand of 61 mmtoe in 2003 from the 1994 level of 34 mmtoe. For Pakistan the GDP growth rate is estimated at 6.5 percent, an energy elasticity of 1.03 and a population growth rate of 3.1 percent p.a. during the next decade. Pakistan will, in the year 2003, need to import a 24 mmtoe at a cost of US$2.4 billion when today energy prices are taken into account.

Energy demand and supply in Pakistan 1999-2003

Year	Total energy demand mmtoe	Domestic supply: Coal mmtce	Coal mmtoe	Oil mmtoe	Hydro TWH	Hydro mmtoe*	Natural Gas bcf**	Natural Gas mmtoe	Total energy supply mmtoe	Demand/ supply gap mmtoe
1993	34.0	4.0	1.9	3.1	20.3	5.1	560	13.1	23.2	10.8
1999	47.0	5.1	2.4	3.2	29.5	7.4	898	21.0	34.0	13.0
2000	50.2	5.3	2.5	3.2	31.5	7.9	954	22.3	35.9	14.3
2001	53.6	5.5	2.6	3.2	33.5	8.4	968	22.6	36.8	16.8
2002	57.1	5.7	2.7	3.2	33.5	8.4	979	22.6	36.9	20.2
2003	61.0	5.9	2.8	3.2	33.5	8.4	993	22.6	37.0	24.0

* Estimate based on a 36 percent efficiency of equivalent oil fired plant.

** 943-977 Btu/cf

Thus, there will be a need for energy imports to Pakistan and India together of 61.3 mmtoe in 2000 which will rise to 93.0 mmtoe by the year 2003, imports which

will impose a considerable burden on the two economies. The annual energy import bill of the two countries will rise from the present US$4.5 billion to US$9.3 billion in 2003.

The composition of energy imports - oil, natural gas, or coal - will clearly depend on the price of supply of the various fuels, the demand pattern, the technology and the geographical location of the demand in the two countries. At present, the energy deficits in the two countries are being met almost entirely through import of crude oil or petroleum products. Based on a comparison of fuel costs at the plant gate, a netback value analysis for both countries reveals that natural gas, whether landed as pipelined gas or as LNG and subsequently regassified, can compete with kerosene and LPG in the domestic and commercial sector, with naphtha in existing fertilizer production, with fuel oil or diesel in combined cycle power generation and with coal in non-pithead base-load power production as long as the landed price for the natural gas does not exceed a US$3.5/mmBtu level; at that price it will not compete with heavy fuel oil or coal in industrial heat and steam raising, with naphtha in new greenfield fertilizer production or with coal-based pithead power production. It seems therefore that natural gas can play an important role in meeting the commercial energy deficits in the two countries.

A market analysis carried out sector-wise by consultants has estimated the total demand for gas at 4,000 mmcfd in 2000 and 6,400 mmcfd in 2003 in India. Taking into account the projected domestic gas production, the demand for imported gas is estimated at about 1,450 mmcfd in 2000 which rises to about 3,800 mmcfd in 2003[3]. Beyond 2004 there will be need for even greater imports of gas as the domestic production declines. In the case of Pakistan, it is estimated that demand for gas will be 3,000 mmcfd by the end of the decade and will rise to 3,650 mmcfd by 2003. Since indigenous supply (allowing for expected new discoveries) is expected to grow from 2,650 mmcfd in 2000 to 2,950 mmcfd in 2003, the inference is that the demand for imported gas will be about 350 mmcfd in 2000, but would rise to over 700 mmcfd in 2003. Barring any major new oil or gas discoveries in the interim period, demand for imported gas is expected to keep increasing thereafter. Thus, at a minimum the need for import of gas to the subcontinent may be estimated at about 1,800 mmcfd in 2000 but which will rises rapidly to 4,500 mmcfd in 2003.

Six countries, namely Iran, Oman, Qatar, Turkmenistan, U.A.E. and Yemen have exportable gas reserves. Iran, with reserves of 730 tcf, has entered into agreements for feasibility studies for onshore pipelines to India and Pakistan, as also to Europe. But its gas fields, while containing vast reserves, are far from being developed. Given the political climate and financing constraints to develop the gas fields, no immediate development of the gas fields in Iran, Turkmenistan (reserves of 80 tcf) and Yemen (unassessed) can be foreseen. Oman, with reserves in the range of 20 tcf, has studied transporting gas to India by both a shallow offshore pipeline along the Iran and Pakistan coasts and by a 3,000 meter deep sea line. Simultaneously, it has also been actively promoting a project for export of LNG by a consortium of the Oman Liquid Natural Gas company, Shell, Total, Partex of Portugal and a number of Japanese companies. But it

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[3] The deficit of 3,800 mmcfd in 2003 is split at 1,000 mmcfd in the southern region and the balance in the north and the west.

appears that there may not be enough gas reserves to sustain both the pipeline and the LNG projects. U.A.E. is a traditional exporter of LNG to the far east, particularly Japan, and could export an additional 2 million tons of LNG since it is planning on extending the Das Island LNG facility from the current 4.8 million tons. Qatar has 160 tcf of gas reserves and has four LNG projects for selling 26 million tons of LNG in different stages of evolution. Qatar is also examining gas pipeline and LNG export projects to India and Pakistan. It is not unthinkable that the recently revived Natuna LNG project, with recoverable hydrocarbon reserves estimated at 45 tcf, could also become a potential supply source for the subcontinent in the early part of the next century.

There are a number of options for the import of gas to India and Pakistan which need to be evaluated: onshore pipelines from Iran and Turkmenistan; offshore pipelines from Qatar, Iran and Oman; combination of offshore and inland pipelines; and LNG from existing plants or from new constructions in the mid east. Preliminary evaluations by the various consultants indicated that cost of delivered gas through onshore pipelines could range from US$1.43 to 1.85 /mmBtu, for offshore pipelines from US$1.9 to 2.2 /mmBtu, while LNG costs would be in the range of US$2.62 to 4.62/mmBtu. These estimates, however, were based on assumptions that lacked consistency, in particular on the yearly volumes. There is, therefore, some concern that the LNG transportation costs may have been overstated in the consultant reports. Our own calculations show that it should be possible to deliver a 1,500 mmcfd based volume of LNG (after regassification) from the mid-east to the subcontinent at a transportation cost just below US$3/mmBtu. Prima facie, it seems that natural gas transported through pipelines should have a delivered cost of less than that for LNG, the difference depending on whether the pipeline is onshore or offshore, the location of the market, and also any transit charges that may be levied by the countries over whose land the line traverses. But, given the recently reported tendency of decreasing costs for large-scale LNG projects, the difference in costs may be much less than are presently being estimated. This is particularly true if a major market is located further than has been recognized by the consultant reports, for example, the south east of India which would need an additional 1,000 mile onshore pipeline from the landfall point in western India.

In analyzing and interpreting these cost figures it must be kept in mind, however, that the underlying traditional economic analysis is not the ultimate decisive factor in final decisions on major private sector infrastructure projects. What matters ultimately is the <u>financial</u> viability of the project, the strength of its sponsors and its risk structure. Therefore, in the evaluation of the optimum alternative modes of gas transport, a number of factors, in addition to the delivered price of gas, will need to be taken into account in reaching a decision. These include:

- Political risk
- Market risk
- Commercial and project risk
- Coordination of downstream investments with import volumes
- Financial resource mobilization mechanisms
- Security packages.

Mechanisms for Financing

The most important challenge in gas import projects is the arrangement of a viable financing scheme. Most common is the "build-own-and-operate" (BOO) scheme, in which private investors mobilize the required capital, build the transmission infrastructure (LNG or pipeline), and operate the system under a take-or-pay contract with a gas company in the importing country. The success of such a scheme would require that:

(i) The private investor has the financial capacity to provide the equity funds of about 25-30 percent of the project cost. In many gas export projects the project cost, excluding the downstream market development, is in the order of US$4-5 billion, implying equity investments of US$1-1.5 billion. Many of the proponents of BOO schemes do not have a financial capacity close to this level.

(ii) An instrument is developed to cope with political risk. Private investors do not enter easily into situations where there is significant political risk. This clearly becomes a more serious consideration when large investments with long gestation periods are at stake. Under these circumstances, a guarantee instrument would economize private sector participation considerably. This kind of instrument can be developed in conjunction with private insurance programs or with multilateral institutions.

Potential financiers of international gas projects will also be greatly encouraged to participate, when most or all of the following conditions are fulfilled as well:

(iii) The project has full political support of the exporting and importing governments, as well as of the governments through whose jurisdictions the gas will be transited.

(iv) The consortium that is launching the project may have to include one or several major international oil or gas companies.

(v) The implementation of the project must be in reputable and experienced hands.

(vi) Long term contracts with unconditional commitments, including take-or-pay clauses, must be signed.

Recommended Strategy for Gas Trade

Based on an analysis of the above factors, the tentative recommended strategy for import of gas should incorporate the following:

- *Multiple vs. single gas sources.* A multi-source approach is possible in view of the size of the need for imports of gas of 4,500 mmcfd and would alleviate political risk perceptions.
- *Total investment needs.* The total investment needed for natural gas import should include also the downstream infrastructure necessary to deliver the gas to the consumer.
- *Coordination of supply and demand.* In view of the large investment requirements, both upstream and downstream, graduated market development in phase with the upstream construction is highly desirable. The economies of scale that may be

possible through larger upstream systems need to be balanced with the possibilities of asynchrony in the completion of the downstream markets.

- *Allocation and management of risks.* The political, market, commercial and project risks will have to be shared between the governments, the developers and the international financial institutions.
- *International financial institutions participation.* Since both the investment requirements, political and market risks of these projects are so great, the participation of the international financial institutions seems essential. The role of these institutions could be to provide technical assistance, help in the financial structuring of the projects, development of appropriate security packages, and use of guarantee instruments.
- *Lead institutions for project development.* There is a need for clarity in the responsibility and the process for development of a project which is complex. involves a large number of domestic agencies, and is international in scope. The countries could nominate specific agencies to develop specific projects as outlined above, but with an oversight committee for final decisions, within a specified time frame.

It is important to stipulate that, before any gas is imported, the energy pricing system in the gas receiving countries has been reformed in such a way that it is based upon sound economic principles. This implies that existing pricing policies should be revised and subsidies on specific energy products be abolished. It also entails the abolition of the existing gas allocation policy of the government.

Taking into account the above considerations, it seems clear that one way to a successful implementation of gas import projects for Pakistan and India is to have them set up as joint ventures, in which the private sector has a major share in and responsibility for the construction and operation of the gas import schemes, while governments of exporting and importing countries hold an effective share in the projects. Given the perception of political and market risks, these projects are unlikely to come to fruition without some participation - in the form of loans and/or guarantees - of one or more international financial institutions. In addition, such participation seems necessary because:

(i) major oil and gas companies (and other foreign investors) do not want to form project companies which are perceived by the governments of the exporting and importing countries as total foreign entities. The oil and gas companies are very much eager to create a project company which has at least some local ownership.

(ii) the private investors, while happy to see that governments are not running the gas export/import business, definitely seek minor shareholding by the governments to ensure that they procure cooperation, partnership and an accommodating business environment.

(iii) the major oil companies have separated their operations into independent profit centers. They therefore cannot cross-subsidize some activities or regions with the hope of very long term rewards from these activities or regions. This means the oil companies' ability to take certain types of risk is much more limited than in the past.

(iv) the large investments, the long gestation of the projects and the political risks involved necessitate some measures for risk mitigation. These could be made available through some form of explicit guarantees -such as the guarantee instrument, developed by the World Bank, or private insurance programs- or through direct financial participation of international financial institutions.

(v) there is a need for an agency to facilitate cooperation among the investors, the involved governments and other major players. Such role can be most effectively played by international financial institutions.

Gas import projects, whether by pipeline or as LNG, will require a structure that permits the mobilization of finance from domestic and international sources. In the case of pipelines, three separate modules are possible: gas production in the exporting country, pipeline transportation, and gas sale in the importing country. For LNG projects, the additional modules would be for liquefaction of gas in the exporting country, transportation by LNG tankers instead of by pipeline, and regassification in the importing country. The financing and operation of each of these modules can be assigned to separate agencies, both domestic and foreign, but always as part of the overall gas project.

It is also important to note that, in the World Bank's new oil and gas lending strategy, transnational gas trade projects are recognized as an area of highest priority for Bank assistance.

For India, a possible mix of projects for satisfying gas demand till 2003 would be:

- A 600 - 1,000 mmcfd LNG scheme for south east India.
- A 2,800-3,200 mmcfd onshore/offshore gas pipeline system from Oman and/or Qatar. It is less probable, but not to be excluded, that Iran and/or Turkmenistan could supply part of these volumes in the timeframe mentioned. For the longer term they are important potential suppliers of substantial quantities of gas for the South-Asian region.

For Pakistan, the approach would be for the following projects till 2003:

- An onshore pipeline from Qatar with a capacity of at least 700 mmcfd. Because the gas demand will grow very rapidly after the year 2003, it probably makes economic sense to build a pipeline with a higher capacity.

Because the suggested gas import projects for Pakistan and India have a substantial part of the pipeline routing in common, it seems that coordination in the construction of pipelines that bring gas to both countries has some merits. Taking into account the big quantities of gas that each of the countries will need in 2003 and thereafter, a transportation system with at least two pipelines and in the long term probably more seems necessary if the gas is to come from the Qatar/Oman region.

For Bangladesh, the only country on the subcontinent with some export potential, the key policy decision is to invite international oil companies for oil and gas exploration, but with clearance for export of gas beyond that required for domestic market. This could be achieved by the government offering the private sector the alternatives of; (i)

purchase of reserves after discovery at a determined price, (ii) purchase of natural gas earmarked for domestic market up to a level determined at contract stage with the balance to be disposed by the company, or (iii) export of gas to any country depending on the price.

1

Regional Energy Sector Overview

Introduction

Bangladesh, India and Pakistan demonstrated strong economic growth rates during the 1980s. The 1990s opened with a deceleration of the growth, which, however, did not last long. During 1980-92, GDP grew on an average at 4.2 percent in Bangladesh, 5.2 percent in India and 6.1 percent in Pakistan. The prognostications for future growth are even better. Economic growth and increase in use of commercial energy go hand-in-hand and result in reduction in use of non-commercial energy (most of which is fuelwood). Although all three countries possess substantial energy resources in one form or another, they all are net importers of energy, mostly oil and oil products.

Energy Reserves and Supply

Historically, coal, oil and natural gas have been the most important contributors in satisfying the region's overall demand for commercial energy. There is, however, substantial variation in the mix of used commercial energy in India on the one hand and in Pakistan and Bangladesh on the other, due to the difference in available natural energy resources in the three countries. In Bangladesh, natural gas is in abundance. It is almost the only domestic fuel, supplying 74 percent of the demand for commercial energy. The issue there is if that country should consider exporting natural gas and, if so, when and how. India has vast coal reserves, some substantial oil and gas reserves, and hydropower; nevertheless, it has been importing crude oil and oil products in ever rising quantities, as the demand-supply gap for commercial energy keeps widening. Pakistan has substantial gas reserves, with new discoveries continuing to be made. Its oil and coal reserves are, however, limited and the hydropower resources are difficult to develop. Pakistan too has been importing oil and oil products in rising volumes, as the demand for commercial energy has been running ahead of a slower paced but growing domestic supply, including new gas. In the following a brief overview of the recent commercial energy supply situation is given.

India: In 1992, India's primary energy supply (including imports) was about 205 mmtoe, comprising 174 mmtoe of domestic production and 31 mmtoe of

imported energy. Of the suppply, coal and lignite accounted for 54 percent, oil (about one-half of which was imported) 27 percent, hydropower for about 13 percent and natural gas for about 6 percent. Although domestic production of crude oil increased sharply after the discovery of Bombay High in the mid 70s, India has continued to import oil. Coal is the main primary resource, not only for direct use in industry, but also in indirect uses of energy through power generation. Coal's share in the supply has maintained a proportion around 54 percent for the last twenty years. Oil too maintained over these years its proportion in the supply at around 30 percent, but with 'swing' in the share of imported oil in total oil consumption.

Natural gas, being the main alternative to coal and oil in the Indian energy scene with a domestic production of 560 bcf in 1992, is likely to play an increasing important role in the coming years, thereby displacing the traditional fuels in the market and supplying incremental energy demands: the forecast gas production for the year 2000 is 940 bcf. The reason for this is that natural gas is environmentally far more benign, also it has economic advantages when used as a fuel for power generation. Natural gas recorded a 6 percent share in primary energy consumption in 1992, against 1 percent only in 1973. There has been a growing appreciation of the value of natural gas and its attractiveness as a substitute for oil and coal, so much that flaring of gas which was around 50 percent of production in the early 1970s has declined steadily and would be almost zero by the mid 1990s.

Pakistan: Natural gas has been the most important contributor to the energy supply in Pakistan, constituting 42 percent (13.0 mmtoe) in 1992. Oil followed with 38 percent, hydropower with 13 percent and coal with a modest 7 percent. Energy imported almost wholly consisted of oil and oil products, domestic oil meeting only a quarter of the oil requirements. Consumption of commercial energy has been growing at about 8.5 percent p.a. over the last decade and with energy conservation measures in place is expected to show a future growth of 6 to 7 percent p.a. Natural gas is foreseen to remain a very important contributor to the energy supply when more gas fields are discovered as expected. Pakistan is gas prone and gas reserves account for 90 percent of the discovered hydrocarbon reserves. Natural gas production has increased 4-fold since 1973 with utilization in power and fertilizers. Indications are that domestic gas production would reach a level of about 1,050 bcf per year in the early years of the next century (600 bcf in 1992) and stay at that level for a few years before declining.

Bangladesh: In 1992, primary commercial energy consumption in Bangladesh was 6.8 mmtoe, of which natural gas accounted for 60 percent, oil for 32 percent, hydropower for 4 percent and (imported) coal for 4 percent. The bulk of the gas consumption was in power generation and fertilizer production, together accounting for 83 percent of the 1992 gas usage in the country. With increased gas availability and the government's policy of substituting natural gas for imported petroleum products, the country's dependence on imported energy was significantly reduced in the 1980s. Natural gas is forecast to play an increasing role in satisfying the projected energy demand growth, specifically in the power generation sector.

Economics of Using Gas vis-a-vis Alternative Fuels

Natural gas competes with alternative fuels in nearly all its applications. The economic value (or netback value) of natural gas in its various applications is that price of the gas, at which the unit cost of production of the final product (electricity, fertilizer, heat) will be the same as the unit cost of production, based on the alternative fuel/feedstock in those applications. In economic terms, the netback value of gas gives an indication of the price, at which the consumer of the gas is indifferent whether he uses gas or the alternative fuel/feedstock in his specific application. Within each category of consumers, however, gas will have a range of netback values which will be dependent on the characteristics of individual consumers in terms of their location, mix of alternative fuels/feedstock, pattern of fuel use, etc. In the following, therefore, we have estimated *benchmark*, or representative netback values for each consumer class.

Gas in competition with oil

In Pakistan as well as in India, producer and consumer prices of oil products and natural gas are administered by the federal government. Annex 1.1 gives an overview of the January 1993 consumer prices of some oil products and natural gas, as in force in India and Pakistan, together with the prices for OECD Europe. As long as such regimes of administered energy prices with implicit subsidies for certain products and/or consumer categories exist, it is impossible to assess the long term degree of price competition between (subsidized) natural gas on the one hand and its (subsidized) competitors, i.e., oil products, on the other. In addition, a tariff structure that does not fully reflect the cost of the various energy resources is not conducive to an efficient use of energy and an optimal inter-fuel substitution. For the purpose of assessing the economic value of gas in relation to its oil competitors, therefore, the international (non-subsidized) crude oil and product prices are the appropriate variables. To avoid the difficulties in assessing the rather varying inland transportation cost of oil products, gas and coal, depending on which specific location and which specific type of end-consumer in the vast south Asian region is chosen, a certain simplification has been adopted in that the oil prices CIF Bombay/Karachi have been assumed to be the yardstick for assessing the economic value of natural gas at these coastal delivery points. In Table 1.1 the most relevant CIF Bombay/Karachi product prices are listed, based on a price of crude oil of US$18/bbl, FOB Arab Gulf. Product prices would increase US$7-8/tonne for a US$1/bbl increase of the FOB crude oil price, except for LPG, which would increase US$11-12/tonne.

Table 1.1 product prices, CIF Bombay/Karachi, at crude price of US$18/bbl, FOB, Arab Gulf

Product	*CIF price US$/tonne*
LPG	185
Naphta	180
Kerosene	215
Gasoil	190
Fuel oil (low sulphur)	120.
Fuel oil (high sulphur)	90

Gas in competition with coal

Natural gas competes mainly with coal in the industrial and power generation sector. As already was mentioned above, India is well endowed with coal reserves, while Pakistan currently has hardly any substantial coal production. A large proportion of the coal reserves in India is of low quality with a high ash content; this prohibits from an economic point of view its long distance transport from the generally remote coal mines, mainly in central-east India, to the main consumption areas in the western and southern parts of the country. Pithead prices of coal are fixed by the central government and are, at a level of around US$0.5/mmBtu for average quality (16 mmBtu/ton) power station-destined coal, just below or at par with the cost of production, but well below international prices. When royalties and transport fees, however, are added to the pithead price, the average power station delivered price for coal in western India is in the same order of magnitude (US$1.6-1.8/mmBtu) as the price for imported steam coal (26 mmBtu/ton) at the Indian west coast or Karachi. As a yardstick for coal prices for power generation we assume, therefore, the prices as specified in Table 1.2:

Table 1.2 Prices of coal for power generation

Coal destination	*$/tonne*	*$/mmBtu*
Pithead	7.5	0.5
Westcoast	25.0	1.6 - 1.8
Southern region	25.0	1.6 - 1.8

Although the domestic coal reserves are substantial, the growth in coal production is limited, due to financial, environmental and social restrictions. Based on the realized growth rates of 5.4% for coking coal and 6.7% for non-coking coal during the 1980's, and

taking into account that railway transportation capacity in the country is currently more than saturated, it is foreseen that the growth in coal production will not exceed 5% p.a. Annex 1.2. gives an overview of realized coal production over the past 10 years.

In the Southern region, comprising Andhra Pradesh, Karnataka, Kerala and Tamil Nadu there is a certain amount of coal and lignite production within the region. But this is well below the overall primary energy requirements for power generation, cement production and other industrial uses. Coal from outside the region from mines beyond 1,000 kms, is regularly transported by rail. More and more of such coal, subject to availablity, has to be transported in as the energy demand grows in the region.

In order to assess the economic viability of gas use in existing and future applications, *benchmark* netback values for gas in the main consuming sectors have been estimated. These netback values are calculated based on the prices of the fuels/feedstock displaced, as represented in Table 1.1 and Table 1.2 above, and taking into account the different efficiencies in end use between natural gas and its alternatives, together with differential capital and operating costs of the gas and non-gas applications. Because Tables 1.1 and 1.2 represent oil and coal prices for both India and Pakistan, the estimated benchmark netback values for gas, which are based on these prices, hold for both countries.

The *benchmark* netback values of natural gas for various applications are estimated to be as in Table 1.3.

Table 1.3. Benchmark netback values of gas

End use	*Netback value (US$/mmBtu)*
Residential/commercial	
• new commercial consumer	6.7
• new residential consumer	3.5 - 7.0
Combined cycle power generation	
• fuel oil replacement	4.3
• diesel replacement	6.4
Base-load power generation	
• coal replacement *	
- pithead	2.3
- westcoast-area	3.7
- southern region	3.7
Industrial heat and steam raising	3.0
Fertilizer production	
• future greenfield	2.2
• existing plants	5.0

*Cost for flue gas desulfurization (estimated at US$0.5/mmBtu) and for additional coal infrastructure have not been taken into account

Annex 1.3 gives an overview of the assumptions and the procedure used to calculate the netback values and shows some of the calculations supportive of the conclusions in Table 1.3. It must be noted that the above benchmark netback values for gas have an indicative character only and should not be used to make final investment decisions. The netback values for power generation, for instance, do not include any environmental premium. Only an in-depth economic and environmental analysis of the power sector could in the end determine the advantage of using gas vis-a-vis domestic coal.

The results in Table 1.3. show that residential/commercial use of natural gas would have the highest netback values, for new residential consumers depending on the stage of development of the gas distribution grid: the higher value of US$7.0/mmBtu represents the marginal customer in a well-developed distribution system, the lower value of US$3.5/mmBtu is applicable in areas where gas is available, but a grid has yet to be developed. The high values are due to the replacement of high value liquids, large end use efficiencies for natural gas applications and - in case of an existing distribution grid - relatively low incremental investments. The high residential/commercial netbacks are directly followed by the netbacks, based upon gas use in combined cycle power generation, where gas is substituting diesel or fuel oil. Use of natural gas instead of coal in power

production would be economically feasible only in non-pithead generation, assuming a gas import price level of US$3.5/mmBtu. Pithead generation of electricity has economic advantages over gas fired power generation; this holds, however, only when the power is consumed within a distance less than about 400 miles from the location where the power is generated. Beyond that distance the transportation cost of electricity becomes prohibitive to compete with locally gas generated electricity; in other words, when the distance between coal mines and the coastal consumption areas of power is greater than about 400 miles, gas generated power can compete with power generated at the coal mine mouth. With the above gas import price of US$3.5/mmBtu, gas use in fertilizer production seems feasible only in existing plants, where the capital investments are considered to be sunk costs; taking into account the currently low world market prices for urea, new greenfield urea plants would be no viable option for usage of gas with the above import price level.

2

Commercial Energy Demand and Supply By Country

Bangladesh

Proven remaining recoverable natural gas reserves in Bangladesh are estimated at 12 tcf (or 340 bcm). The current yearly consumption of gas is about 200 bcf, giving a reserve to production ratio of 60 years. Even with a forecast gas consumption of about 480 bcf in the year 2003 , this ratio remains at a comfortable 25 years. Bangladesh has a very low energy consumption per capita, at about 60 kgoe per year, and as its economy grows, gas consumption would grow even faster. Table 2.0 gives a forecast of the supply of natural gas in the country, together with the forecast supply of oil and coal, which are imported, and of hydropower.

Table 2.0 Commercial energy supply in Bangladesh 1999-2003 (mmtoe)

Year	*Oil*	*Natural Gas*	*Coal*	*Hydro*	*Total*
1993	1.6	4.9	0.5	0.2	7.2
1999	1.4	8.7	0.5	0.2	10.8
2000	1.3	9.4	0.5	0.2	11.4
2001	1.3	9.8	0.6	0.2	11.9
2002	1.2	10.6	0.6	0.2	12.6
2003	1.1	11.5	0.6	0.2	13.4

Allowing for this growing gas consumption, there may be a rationale in the government's reported wish to preserve the existing gas reserves as "national reserve". But, the exploration for hydrocarbons in the country, which is considered gas prone, is far from complete. International oil companies have been highly interested in exploration, onshore as well as offshore. Their enthusiasm apparently gets a set back, however, when the Government of Bangladesh (GOB) shows disinclination to commit to export of new gas, which should be possible for at least the new discoveries. India is a "natural" market for the

gas, unless the new finds are so large that LNG exports to Thailand or other countries in the Far East become feasible. For the time being, it is a change of policy that is required from the GOB before any meaningful study of gas trade, involving that country, can be undertaken.

India

Energy resources

India's energy resources and their 1992 production, with the resulting reserves/production ratio, are shown in Table 2.1 below:

Table 2.1 Energy reserves in India (as of 1992)

Reserves	*Recoverable*	*Production in 1992*	*Reserves/production ratio (years)*
Coal, million tonnes	70,000	255	280
Crude oil, million tonnes	806	31	26
Natural gas, billion cu.ft.	26,000	660	40

Although the coal reserves are vast, logistics and economics have limited the growth in the annual output of coal to about 5 percent. Crude oil and natural gas reserves seem to have peaked, at least for now; as a result, when annual production increases, specially that of natural gas, the reserves stand to be depleted in less time than shown under the reserves/production ratio. India has a hydropower potential of 84,000 MW, of which 14 percent has been developed so far. Practical problems have prevented further significant hydropower development.

Demand for commercial energy

Projections of total commercial energy consumption and the domestic energy supply in the years 1999-2003 are represented in Table 2.2. These are the first years when import of natural gas may happen, if action to do so is initiated over the next few months. Total energy demand is prognosticated on the basis of an energy consumption growth rate of 6.5 percent per year until the year 2000, and 4.5 percent per year thereafter. The domestic supply of energy is assumed at the maximum likely figures; imports of oil, gas and coal would make up the remaining demand/supply gap.

Table 2.2 Energy demand and supply in India 1999-2003

Year	Total energy demand mmtoe	Domestic supply: Coal mmtce*	Coal mmtoe	Oil mmtoe	Hydro TWH	Hydro mmtoe**	Natural Gas bcf	Natural Gas mmtoe	Total energy supply mmtoe	Demand/ supply gap mmtoe
1993	246	191	134	30	102	36	517	13	214	32
1999	318	253	177	41	98	34	955	24	276	42
2000	332	266	186	40	102	36	955	24	285	47
2001	346	276	193	38	106	37	955	24	292	54
2002	365	287	201	36	110	38	955	24	299	66
2003	374	299	209	33	113	39	955	24	305	69

* mmtce=0.7 mmtoe

** Estimate based on a 25 percent efficiency of equivalent oil fired plant.

As can be seen from the table above, the demand/supply gap is substantial, corresponding with 13.2 percent of total energy demand in 1999, rising to 18.4 percent in 2003. Which fuels must be used to fill the gap and how much of each is subject to strategic, economic and political considerations. It is clear that natural gas can play an important role in satisfying the unfulfilled demand for commercial energy. To put that in perspective: the estimated gap of 42 mmtoe in 1999 corresponds with 49 bcm or 1,750 bcf of natural gas on a yearly basis, this is 4,775 mmcfd.

Demand for natural gas

In 1992 total consumption of natural gas in India reached 510.3 bcf, of which 55 percent was used for energy purposes and 45 percent for non-energy usage. Table 2.3 specifies the various usages of the gas.

Table 2.3 Natural gas consumption in FY 1991-92

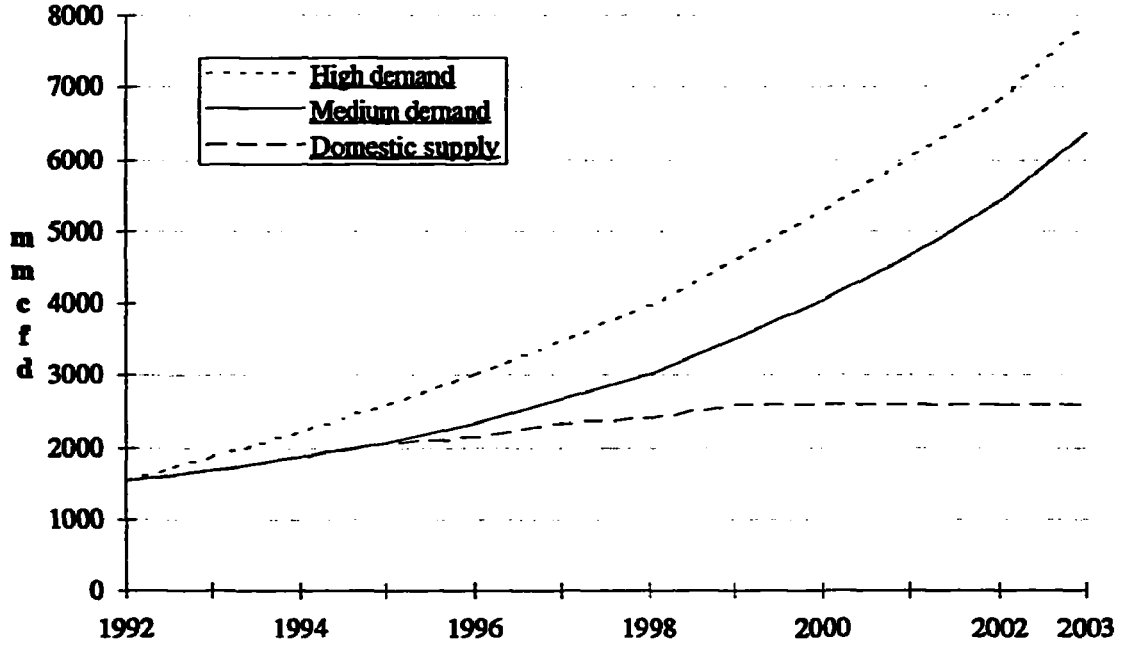
Consumer	Consumption (bcf)	
Energy purposes:		
• power generation	168.7	
• industrial fuel	27.1	
• tea plantation	3.8	
• domestic fuel	2.5	
• LPG production	76.5	
Subtotal		278.6
Non-energy purposes:		
• fertilizer production	194.7	
• petrochemical feedstock	18.8	
• other	18.2	
Subtotal		231.7
Grand total		510.3

Source: Indian Petroleum&Natural Gas Statistics 1991-92

At present, natural gas supplies are allocated to end-use consumers according to a policy, determined by the government. As can be seen from the table above, allocation for fertilizer production and power generation are predominant over other usage of gas. Gas use policy has been a subject of considerable debate in India during the second half of last decennium, but there seems to be a consensus now of how to allocate the available gas to the various consumer categories. It must be noted that a gas allocation policy is aimed to achieve not only an economic objective, but also objectives of social and strategic nature. The preferential supply of gas for fertilizer production in the last decennium (46 percent of total gas consumption) reflects the paramount importance of India's agriculture sector and the GoI's desire to achieve a high degree of strategic independence for the production of fertilizers. The supply of natural gas for power generation, ranked second during the 1980s with 29 percent of total gas offtake, becomes a more and more important allocation of the available gas; the power sector will become the most important consumer category for natural gas in India in the mid 1990s. This is due to the fact that India's demand for electricity is still increasing at a higher rate than the increase in capacity of the power system; that system grew from 30,000 MW in 1980-81 to 72,000 MW (public sector) in 1992-93, with corresponding increase in electricity availability from 110,000 GWh to 284,000 GWh over the same period.

Based on the gas demand and supply data of recent internal Bank reports[4] and external studies, we estimated the gas demand for a high and a medium demand scenario, and the future domestic gas supply as in Fig. 2.1. Annex 2.1 specifies the data.

Fig. 2.1. Future gas demand and supply



[4]Source: Gas Flaring Reduction Project

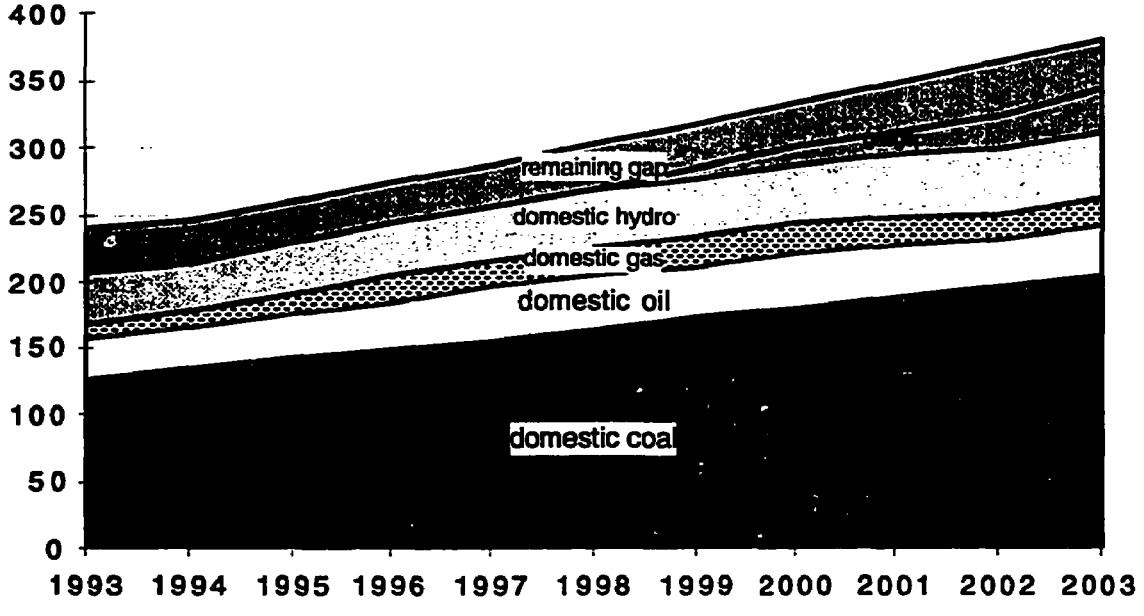
Comparing the natural gas demand/supply gap for the medium demand case in the above Figure 2.1 with the total energy demand/supply gap, as represented in Table 2.2, yields the following data for both gaps and the percentage of the gas gap in relation to the energy gap:

Table 2.4 Energy gap vs. natural gas gap (mmtoe)

Year	*Energy gap*	*Natural gas gap*	*Ratio(%)*
1999	42	8.0	19.0
2000	47	12.7	27.0
2001	54	18.2	33.7
2002	66	25.1	38.0
2003	69	33.5	48.6

It can be seen from the above table and Figure 2.2 below that, based on the projected demand for total energy and for natural gas, the gas gap constitutes about one-fifth of the total energy gap in the year 1999 and about one-half in 2003.

Fig.2.2. Energy demand and domestic supply in India(mmtoe)



If it is assumed that the natural gas gap is fully made up in 2003, the implication is that 33.5 mmtoe or about 3,800 mmcfd of natural gas is being imported in that year. It seems more realistic to assume that any future import scheme for natural gas in about 10 years from now will allow for a maximum of 2000 mmcfd gas import per year. In that event, the ratio of natural gas gap in the energy gap will stand to be reduced to about 33 percent in 2003, leaving a considerable unfilfilled potential demand for natural gas.

Natural gas infrastructure

India does not have an integrated national gas transmission system. A part of India in the west around Bombay and Ahmedabad, and in the west-north-west in Gujarat, Rajasthan, Madhya Pradesh and Uttar Pradesh receive gas from onshore fields in the region as well as from the offshore fields of Bombay High, Bassein and several other, smaller fields in the Arabian Sea off the western coast. Small coastal areas in Andra Pradesh and Tamil Nadu are similarly linked to proximate onshore and offshore gas fields, holding limited gas reserves. Assam and Tripura also get gas supplies from small onshore fields in the respective states. These independent networks presently carry about 1,600 mmcfd of gas and would be developed to carry about twice as much in due course. The capacity of the western offshore lines and of the HBJ pipeline serving the west-north-west region is under expansion to accomodate the associated domestic supply, which is moving towards peak production (from 1,000 mmcfd in 1993 to 2,000 mmcfd, to be achieved in 1998). The Government of India has recently approved in principle a proposal for a trunk pipeline from the Bombay area to the south of India (distance around 1,800 miles) for the supply of indigenous western offshore gas. If that line is laid and the gas reserves in the western offshore areas are shared with the south, it would seem that the supply to the south could only be made through widening the demand/supply gap for natural gas in the Bombay and HBJ region. If, on the other hand, natural gas is to be imported from the Middle East, the proposed trunk line to the south could become an essential piece fitting into a national grid.

Regional gas demand

Expanding on the observations above concerning the proposed gas transmission line to the south, the first fact to note is that of the 'gas gap' of 33.5 mmtoe or 3,800 mmcfd in 2003 in the medium demand case (see para 2.6), about 2,150 mmcfd will be in the west and the north (Bombay, Gujarat, HBJ line and vicinity), about 775 mmcfd in the southern region and the balance in the other regions (but with easier access to coal). Given these large quantities of deficits, also that the demand-supply gap will tend to further widen after 2003, a multi-faceted import strategy of a series of economic packages for import, of varying sources, of different modes of transportation if necessary, of different destinations etc., should be followed. Any package for import, obviously, should be economic; namely, gas should be the optimum fuel to import at the time and place it is needed.

Pakistan

Energy resources

Pakistan's energy resources and their 1992 production, with the resulting reserves/production ratio, are shown in Table 2.5 below:

Table 2.5 Energy reserves in Pakistan (as of 1992)

Reserves	*Recoverable*	*1992 Production*	*R/P Ratio (years)*
Coal, million tonnes	432	3.6	120
Crude oil, million tonnes	27	3.1	9
Natural gas, billion cu.ft.	22,800	551	41

Pakistan's natural gas reserves are about the one resource which is notable. The Government of Pakistan has been liberalizing the petroleum exploration policy from time to time, which has attracted some renewed interest from international oil companies to explore for gas as such. Pakistan has hydropower potential of about 27,000 MW of which some 18 percent has been developed so far. Schemes in progress to harness more hydropower should double the hydel output by the year 2000. The production of coal and gas is expected not to grow substantially in the near future.

Demand for commercial energy

Projections of total commercial energy consumption and the domestic energy supply in the years 1999-2003 are represented in Table 2.6. These are the first years when imports of natural gas may happen, if action to do so is initiated over the next few months. Total energy demand is prognosticated on the basis of an energy consumption growth rate of 6.5 percent per year until 2000, and 6.7 percent per year thereafter. The domestic supply of energy is assumed at the maximum likely figures; imports of oil, gas and coal would make up the remaining demand/supply gap.

Table 2.6 Energy demand and supply in Pakistan 1999-2003

	Total energy demand	*Domestic supply*							*Total energy supply*	*Demand/ supply gap*
		Coal		*Oil*	*Hydro*		*Natural Gas*			
Year	*mmtoe*	*mmtce*	*mmtoe*	*mmtoe*	*TWH*	*mmtoe**	*bcf* * *	*mmtoe*	*mmtoe*	*mmtoe*
1993	34.0	4.0	1.9	3.1	20.3	5.1	560	13.1	23.2	10.8
1999	47.0	5.1	2.4	3.2	29.5	7.4	898	21.0	34.0	13.0
2000	50.2	5.3	2.5	3.2	31.5	7.9	954	22.3	35.9	14.3
2001	53.6	5.5	2.6	3.2	33.5	8.4	968	22.6	36.8	16.8
2002	57.1	5.7	2.7	3.2	33.5	8.4	979	22.6	36.9	20.2
2003	61.0	5.9	2.8	3.2	33.5	8.4	993	22.6	37.0	24.0

* Estimate based on a 36 percent efficiency of equivalent oil fired plant.

** 8.4-8.7 mega calories per cu.meter

As can be seen from the table above, the demand/supply gap is substantial, corresponding with 28 percent of total energy demand in 1999, rising to 39 percent in the

year 2003. For satisfying its energy needs, Pakistan will thus become more and more import dependant. To illustrate, the energy demand/supply gap for the year 2003 of 24 mmtoe corresponds with 1,050 bcf of natural gas on a yearly basis, this is 2,900 mmcfd.

Demand for natural gas

In 1991, total consumption of natural gas in Pakistan reached 481 bcf, of which 40 percent was used for power generation, 22 percent for industrial usages, 20 percent for fertilizer feedstock and fuel, and 17 percent for residential and commercial use. Table 2.7 gives details of the 1991 gas consumption, as realized by the two gas transmission and distribution companies, Sui Northern Gas Pipelines Limited (SNGPL) and Sui South Gas Company (SSGC), and the Mari gas transmission company which delivers Mari gas directly to power and fertilizer plants.

Table 2.7 Gas consumption in 1991 (bcf)

Consumer	SSGC	SNGPL	Mari	Total
Power	66	33	96	196
Fertilizer	-	33	66	99
Industrial	50	56	-	106
Residential	24	43	-	67
Commercial	4	9	-	13
Total	144	175	162	481

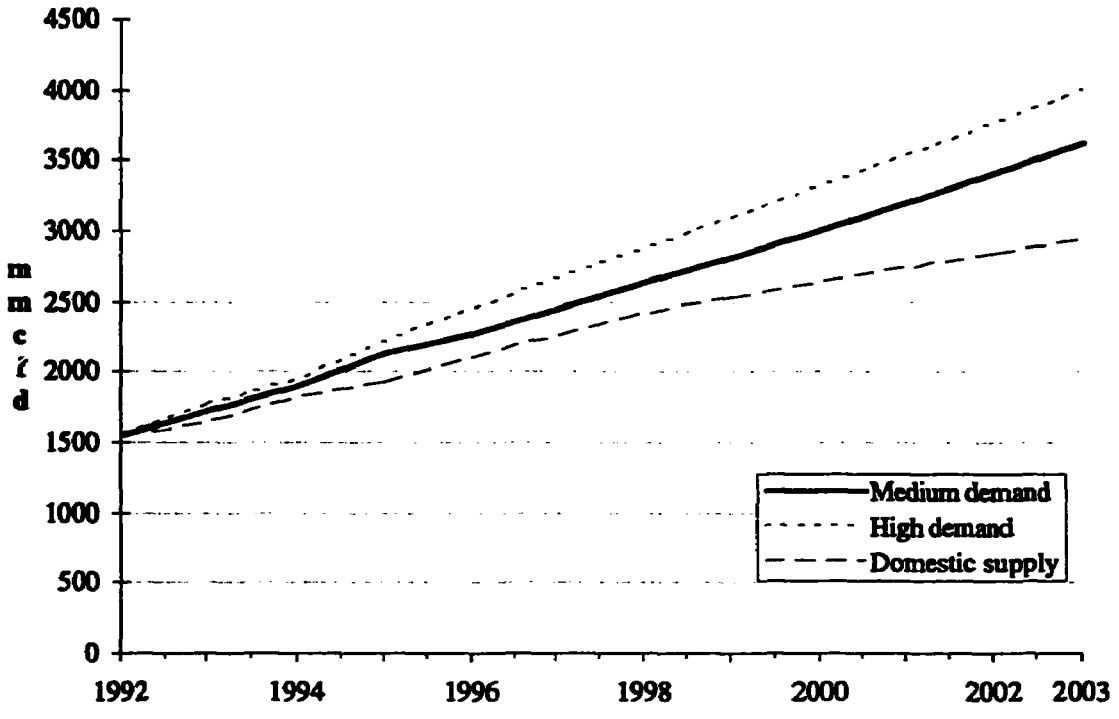
Source: SSGC, SNGPL, Ministry of Petroleum and Natural Resources

Natural gas supplies are allocated to end-use consumers according to a policy that is determined by government. In descending priority, these allocations are for: (i) fertilizer production; (ii) diesel replacement for power generating turbines; (iii) kerosene replacement in the residential and commercial sectors; (iv) fuel oil displacement in the industrial sector; (v) fuel oil displacement in steam turbine power plants, and (vi) fuel oil displacement in cement and steel production. The preferential supply of gas for existing (and planned) urea production reflects the paramount importance of Pakistan's agricultural sector and the Government's desire to achieve a high degree of strategic independence for fertilizer production. The high priority afforded to to residential and commercial users reduces the need for imports of expensive fuels such as kerosene and LPG, and eases the demand for fuelwood which has resulted in serious soil degradation problems in the country. Since in coming years the competition for available gas supplies becomes more intense, an important element of the future allocation policy is the provision of supplies to uses which provide the highest economic benefit to the economy.

Based on what was recently (early 1994) reported in the Bank's ESMAP study on Natural Gas Reserve Assessment and Import Strategy for Pakistan, in Figure 2.2

a high and medium demand scenario, together with a most likely scenario for future domestic gas supply is given. Annex 2.2 specifies the underlying data for this figure.

Fig.2.3. Future gas demand and supply (mmcfd)



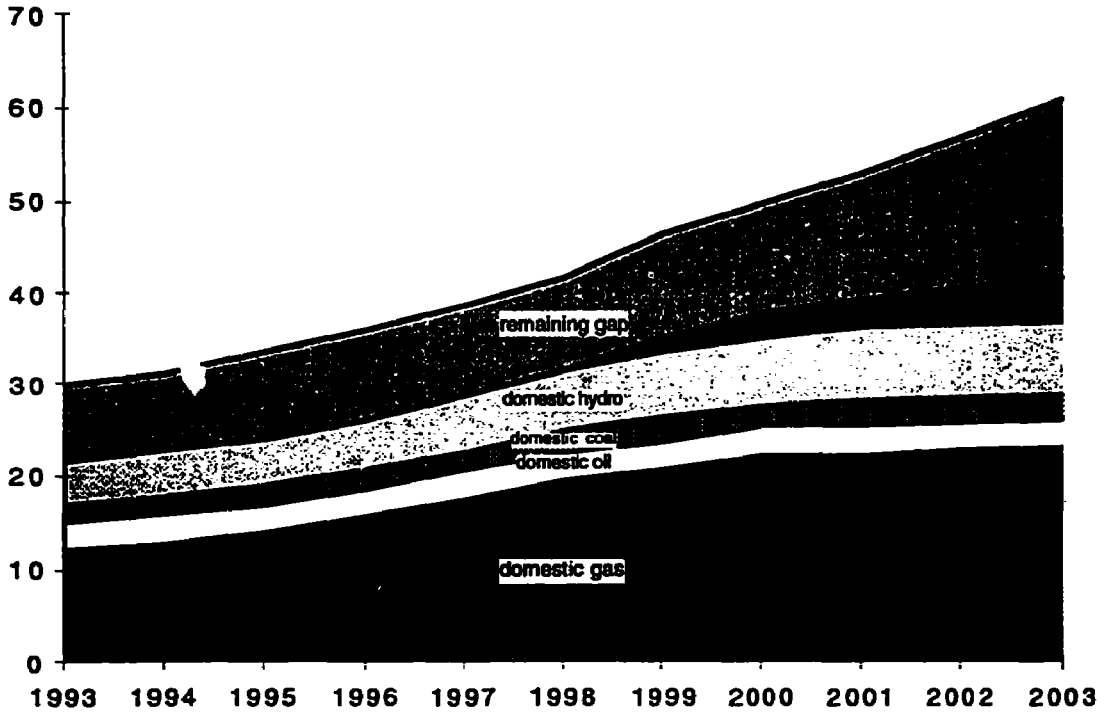
Comparing the natural gas demand/supply gap for the medium scenario in the above Figure 2.2 with the total energy gap, as represented in Table 2.6, gives the following for both gaps, together with the ratio gas gap/total energy gap:

Table 2.8 Energy gap and natural gas gap (mmtoe)

Year	*Energy gap*	*Gas gap*	*Ratio (%)*
1999	13.0	2.0	15
2000	14.3	2.5	17
2001	16.8	3.2	19
2002	20.2	3.9	19
2003	24.0	4.8	20

From the above Table 2.8 and Figure 2.3 below it follows, that the portion of the gas deficit in the total energy gap is steadily rising, although its portion remains rather moderate: in 2003 the gas gap constitutes "only" one-fifth of the total energy gap.

Fig. 2.4. Energy demand and domestic supply in Pakistan (mmtoe)



It must be noted, however, that the referred Bank study indicates, that the demand/supply gap for natural gas is sharply rising after 2003, resulting in a gas supply shortfall in the year 2010 of 2,500-3,000 mmcfd or 21.4-25.7 mmtoe per year. Its share in the total energy gap at that time is expected to be in the order of 25 percent[5]. It is noted here that GOP has been negotiating a project for import of gas by pipeline from Qatar which may deliver 1,100 mmcfd (=9.4 mmtoe) to 1,600 mmcfd (=13.7 mmtoe) commencing from late 1998. From Table 2.8 it would appear that most of the energy gap between 1999-2001 would then be filled by imported gas. An aggressive penetration of the market by natural gas, so that almost all incremental demand for commercial energy is met by gas, would be required if Qatar would deliver the above gas volumes and the data from Table 2.8 are taken into account.

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[5] The presentation to the Bank made recently by one of the involved gas supply consortia shows that in August 1993, 'GOP agreed firm gas import quantities and take-or-pay commitment'. The Principles of Gas Sales are stated as: 'First Gas: late 1998; Daily Qty.: 1,600 mmcfd; Minimum Bill: 70 percent, 1st year; 75 percent, 2nd year; 80 percent, 3rd year and subsequent.' These quantities correspond to 9.6 mmtoe in 1999, 10.3 mmtoe in 2000 and 11.0 mmtoe from 2001. They far exceed the 'gas gap' in Table 2.5 and would also far exceed the 'gas gap' under the high scenario also. In fact, during 1999-2001, almost the whole of the energy gap will be met if gas of the volumes indicated are imported. It is noticed that the unconstrained demand is placed at 4,180 mmcfd in 1998/99 and 4,480 mmcfd in 1999/2000. The high demand scenario in the ESMAP study is about 1,000 mmcfd lower. Therein lies the major difference.

Natural gas infrastructure

Pakistan has developed an extensive gas transmission and distribution system with a total length of more than 2,200 miles major cities, including Karachi, Hyderabad, Sukkur and Quetta in the Sindh and Baluchistan provinces in the south, and Faisalabad, Lahore, Islamabad and Peshawar in the Punjab and North Western Frontier provinces in the north are covered. The two transmission and distribution companies SSGC and SNGPL, operating the southern and northern systems respectively, have embarked on major investment programs to accomodate the additional domestic gas from new fields. There is also a small independent pipeline system for evacuation of gas from some of the fields, in particular the Mari field, and transporting it direct to some big gas consumers.

If gas is imported, it is likely to be landed at Gadani, close to Karachi, and then transported to Karachi at the southern end of the pipeline grid. Other options for landing the imported gas exist, but the Gadani option represents a magnitude of costs which appear optimal. The estimated investments and the average incremental cost of transmission, related to absorbing imported gas of a volume of 2,000 mmcfd or 20.7 bcm per year for that option, are US$2,900 million and US$0.81/mmBtu respectively.

Like India, Pakistan would also be well advised to diversify its energy imports by importing natural gas in addition to the traditional import of oil and oil products. Coal is a candidate for import as well, but it is unlikely to compete with natural gas in power generation, if the landed price of gas does not exceed US$3/mmBtu.

3

Importing Natural Gas

Sources of Gas

India and Pakistan are located in proximity to the gas prone areas of the Middle East and the substantial landlocked gas deposits of Turkmenistan. Six countries, namely Iran, Oman, Qatar, Turkmenistan, U.A.E. and Yemen have exportable gas reserves. In Annex 3.1 an outline is given on the extent of the reserves, the status of their development and the state of readiness to sell gas to India and Pakistan.

Iran is interested in supplying gas and has entered into agreements for feasibility studies for gas pipelines to Pakistan and India. Its gas reserves, however, which are estimated to be as huge as 730 tcf, are far from being developed. In the long run, Iran is indeed a good source for import of gas by India and Pakistan. Given the current political climate and the financing constraints to develop the gas fields, "the long run" could mean a wait of ten or more years before Iranian gas exports to Pakistan and India would materialize.

Oman is anxious to sell gas to India. A MOU appears to have been signed with India for transmission of gas by pipeline. The possibilities of transporting gas by either a shallow offshore pipeline along the coast of Iran and Pakistan or a direct deep sea pipeline have been under study. Because the latter had economic and political advantages over the shallow route, the Oman Oil Company (OOC), whose shares are held by the Ministry of Petroleum and Minerals and that of Finance and Economic Affairs of Oman, had even a proposal before it for the laying of the deep sea line. Simultaneously, Oman was actively promoting a LNG export project by a consortium of Shell, Total and two Japanese companies in joint venture with OOC. It is very likely, however, that the gas reserves of Oman are not sufficient until more are proven (beyond 7 tcf for the LNG project) to sustain both the India pipeline and the LNG export project. The India project may not take off for a few years. In any case, the first priority is being given to the LNG export project targeted to export LNG in 2000 and attention for the present is focussed on it.

The **U.A.E.** is a traditional exporter of LNG to the Far East, particularly Japan. It could export an additional 2 million tonnes of LNG, equivalent to 100 bcf of gas, yearly since it is planning to extend the Das Island LNG facility from the current 4.8 mmtpy. It is unrealistic to assume that this additional LNG capacity will be available for the gas markets in Pakistan or India, because (i) the volumes involved are rather small and (ii)

they will have been contracted long before a decision by the Indian or Pakistan government whether to import gas by pipeline or by ship in the form of LNG would have been taken.

Turkmenistan and **Yemen** are currently not considered as serious candidates for supplying natural gas to India and Pakistan, since no immediate development of the gas fields in Turkmenistan and Yemen is foreseen, mainly due to the political instability and lack of funds in these countries. In the long run, Turkmenistan might become a reliable source of gas supply for the Indian subcontinent when it could share its huge gas production potential with Iran, with the purpose to jointly supply the region with substantial volumes of gas. This could be accomplished by delivering gas from Turkmenistan to the northern gas consuming areas in Iran; corresponding volumes gas from the south Iranian fields are thus available for export through overland pipelines to Pakistan and/or India.

Qatar is - in a time frame of the late 1990s - a firm source to import gas from. The country has about 160 tcf of natural gas reserves, which, for international standards, are enormous. Qatar has four LNG projects for selling 26 mmtpy of LNG, corresponding to just under 1,300 bcf of gas per year, in different stages of evolution, and it is considering to pipeline gas to Pakistan. TransCanada, Brown & Root and Crescent Petroleum are the sponsors of this project; but, as discussed in para 2.12, the market capacity (and the internal infrastructure) to absorb the imported gas in the volumes planned should be developed aggressively.

Recently, Exxon announced that the Indonesian Natuna natural gas project will be revived again. This would entail that a gas plateau-volume of 2.4 bcf per day, in the form of LNG, becomes available. The most likely markets include Japan, South Korea and Taiwan, but it is not unrealistic to assume that the Indian subcontinent could also become a potential destination for this gas.

Mode of Transportation

Based on the availability of of gas reserves as dicussed above, the following choices for pipeline routes or LNG schemes seem theoretically obtainable:

Pipelines

(i)	Qatar/Iran	-India/Pakistan	Overland
(ii)	Qatar/Iran	-India	Overland Iran/shallow offshore Pakistan
(iii)	Qatar/Iran	-India	Shallow water
(iv)	Oman	-India	Shallow water
(v)	Oman	-India	Deep sea
(vi)	Turkmenistan	-Pakistan/India	Overland

LNG

(vii)	Qatar/Iran/Oman/UAE	-India	Grassroot plant
(viii)	Qatar/Oman/UAE	-India	Plant extension
(ix)	Qatar	-Pakistan	Grassroot plant

Cost of Imports

Costs for transportation for the above alternatives have been developed on assumptions as explained below. Annex 3.2 gives examples of the transport cost calculations for LNG schemes, while Annex 3.3 specifies examples for pipeline transport calculations. A summary table, Table 3.1, follows on the next page. The calculations have been developed in the case of the pipelines for transportation of 1,500 mmcfd to one destination in India and one in Pakistan. For LNG, transportation of LNG purchased out of a 11 mmtpy (or 1,500 mmcfd) exporting scheme is considered to one destination in Pakistan and three destinations in India; also for LNG from a 4 mmtpy (600 mmcfd) exporting scheme. A typical grass-root LNG scheme involves in the overall transportation tariff a component of 60-65 percent towards liquefaction, 20-25 percent towards shipping and 10-15 percent towards regassification. The LNG tariffs shown thus include regassification costs. The discount rate is taken at 15 percent, which is what private investors would normally take into reckoning. All costs are in 1994 US dollars. To arrive at the delivered cost of gas, the cost of the gas produced and transported to the liquefaction plant (in the case of LNG) or to the export terminal has to be added. It may be in the range of US$1.00/mmBtu or more. For our analysis we have taken the US$1.00/mmBtu figure.

Table 3.1 Transportation Costs

Source	*Route*	*Destination*	*Distance (kms)*	*Tariff US$/mmBtu (15% DCF)*
Pipelines				
1,500 mmcfd				
1. Qatar/Iran	Overland	Karachi	1,600	1.83
		Ahmedabad	2,200	2.44
2. Qatar/Iran	Overland/}	Karachi	1,600	2.01
	shallow}	Ahmedabad	2,200	2.68
3. Qatar/Iran	Shallow	Karachi	1,600	2.20
		Ahmedabad	2,200	2.92
4. Oman	Shallow	Ahmedabad	1,300	2.53
5. Oman*	Deep-sea	Ahmedabad	1,200	2.30
6. Turkemenistan	Overland	Karachi	1,650	1.86
		Ahmedabad	2,250	2.51
LNG-grass root**				
1,500 mmcfd				
7a. Iran/Qatar		Karachi		2.70
/Oman		Bombay		2.85
		Cochin		3.10
		Madras		3.22
600 mmcfd				
7b. Iran/Qatar		Bombay		3.23
/Oman		Cochin		3.52
		Madras		3.57

*The cost figures used to calculate this tariff are rather speculative because the technology for 3,000m deep subsea pipelines is not proven yet

**Tariffs for plant extension are less by about $0.50/mmBtu

Strategies for Importing Natural Gas

The strategy for Pakistan is simple. A pipeline (or a LNG tanker) would deliver the gas near Karachi and internal costs thereafter become common for either mode of external transportation. As the figures, represented in Table 3.2 below, show, it is obvious that the pipeline overland mode of transportation from an external source is the most cost effective for Pakistan. In that case, the delivered cost of the gas (cost of produced gas of US$ 1.00 plus transportation) at Karachi is US$2.83/mmBtu against US$ 3.70/mmBtu for delivered LNG. Taking into account the netback values of US$3.0 /mmBtu for gas in industrial heat and steam raising and US$ 3.7/mmBtu for gas in coal fired power generation (see Table 1.3), it follows that gas, imported by pipeline, would be

the fuel to be preferred over oil and oil products in industrial applications, as well as over coal in power generation. The LNG option would only be viable when the gas is used in higher netback value applications such as residential and commercial use and combined cycle power generation. Because of its higher cost compared with the pipelined gas, such LNG option should -in the longer term- only be considered as complementary to a pipeline import scheme, when diversification of supply is of vital importance for the gas importing country.

Table 3.2 Transportation cost for Pakistan (Karachi)

Source	*Route*	*Tariff*
Qatar/Iran	Overland	1.83
Qatar/Iran	Overland/shallow water	2.01
Qatar/Iran	Shallow water	2.20
Turkmenistan	Overland	1.86
Iran/Qatar/Oman	LNG	2.70

For India, no simple conclusion is possible. Developing some more components of costs, namely for internal transportation (see Annex 3.4 for details of calculations), the following emerges, vide Table 3.3. Ahmedabad is taken as the entry terminal for all imported gas. From Ahmedabad, inland pipelines would transport the gas to Bombay, Cochin or Madras, to choose some representative geographically dispersed destinations in the south. LNG, if imported, would move directly to these ports.

Table 3.3 Inland transportation costs

Route	*Distance kms*	*Tariff US$/mmBtu*
Ahmedabad-Bombay	500	0.36
Ahmedabad-Cochin	1,560	1.14
Ahmedabad-Madras	1,350	0.98

First, looking at the Bombay-Ahmedabad sector which would also feed gas to the HBJ pipeline, the least cost choices come out as follows:

Table 3.4 Import costs of gas- Ahmedabad/Bombay

Source	*Mode*	*Destination*	*Transmission cost $/mmBtu*	*Gas cost at source $/mmBtu*	*Gas cost at destination $/mmBtu*
Oman	Deep-sea	Ahmedabad/ Bombay	2.30/ 2.66	1.00	3.30/ 3.66
Qatar/Iran	Overland	Ahmedabad/ Bombay	2.44/ 2.80	1.00	3.44/ 3.80
Qatar/Iran	Overland/ shallow	Ahmedabad/ Bombay	2.68/ 3.04	1.00	3.68/ 4.04
Qatar/Oman	LNG	Kandla/ Bombay	2.85	1.00	3.85

In all these choices, natural gas will compete with alternative fuels in a variety of applications including power generation with oil firing or, depending on the location, with domestic coal or imported coal as a fuel (see Table 1.3). Nevertheless, the Oman deep-sea option, it would seem, will take several years to get off the ground since first priority will be given by Oman to its ongoing LNG export project. In addition, it seems to date that the gas reserve position in Oman is not sufficient to allow for both the LNG project and a pipeline export project to India. Another complicating factor is that the technology for deep sea pipelines (2,500-3,000 meter of water depth), although considered to be feasible, is unproven, which makes the time and cost estimates for such a project somewhat uncertain. The Qatar/Iran overland pipeline option also will take time to materialize, particularly if the export is sought from Iran. From Qatar, the pipeline could be laid faster if the Qatar-Pakistan pipeline being sponsored by the currently active consortium of Crescent, TransCanada and Brown and Root is extended to India. There are political overtones to a pipeline through a third country. Further, there are also additional costs as third countries do charge transit fees. The fourth option, that of LNG from Qatar/Oman, is also worth consideration, specially considering that major oil companies are already involved in the projects to liquefy natural gas in both countries and are looking for markets to export LNG. In addition, the cost estimates for the LNG options for the Indian market are not very out of line with those for the pipeline options. Import of LNG does not pre-empt such pipeline transmission projects as could be developed in course of time.

Taking the southern region in India, covering the four southern states, it is necessary to note that an efficient southern electricity transmission grid is in operation. It is being strengthened and modernized under an ongoing Bank project, due to be completed in 1997. The south has a large unmet power demand. A combined cycle power plant to be located anywhere in the region with a capacity of about 2,500 MW to 5,000 MW would but partially meet the demand. The following table, Table 3.5, shows the economic cost of delivered gas at Madras and Cochin. These levels of cost make that the netback value for gas, when it is replacing coal in power generation (US$3.7/mmBtu, see Table 1.3), plus its environmental premium (US$0.5/mmBtu, see footnote of Table 1.3), is about break-even

with the cost of delivered LNG. It must be noted, however, that a more in-depth cost analysis is needed to assess the feasibility of gas fired power generation for the Madras and Cochin regions.

Table 3.5 Import costs of gas - Madras/ Cochin

Source	*Mode*	*Gas cost at source $/mmBtu*	*Transmission cost $/mmBtu*	*Destination*	*Gas cost at destination $/mmBtu*
Oman	Deep-sea	1.00	3.28	Madras	4.28
Qatar/Iran	Overl/shall.	1.00	3.66	Madras	4.66
Qatar/Oman	LNG	1.00	3.22	Madras	4.22
Oman	Deep-sea	1.00	3.44	Cochin	4.44
Qatar/Iran	Overland	1.00	3.82	Cochin	4.82
Qatar/Oman	LNG	1.00	3.10	Cochin	4.10

It will be seen that for the southern region, the LNG option appears the most attractive: Although LNG costs at Cochin could be a little lower than at Madras, the overall merits may lie in importing LNG at or near Madras. It is more centrally situated in the southern electricity grid. Further, from there radial gas lines of small diameters could supply industrial clusters in Hyderabad (Andhra Pradesh), Bangalore (Karnataka), Cochin (Kerala) and Madurai (Tamil Nadu).

The price of LNG

A caveat has to be entered here. As already mentioned earlier, the cost figures used in this report are only best estimates. Reality check is actually to negotiate contracts, all options being kept open, several of which have been indicated above. In this context it will also be pertinent to mention some well known facts about how LNG is normally priced in world trade. LNG is priced either on a CIF basis (delivered at the quay of the receiving regassification terminal) or on a FOB basis (on board of the LNG tanker after liquefaction). Most pricing clauses in LNG sales contracts contain a price adjustment clause, that allows the price of LNG to be adjusted periodically to reflect changes in the price of the commodities, to which the LNG price is pegged. Most price indexation mechanisms refer to a 9 or 12 month averaged price of a basket of crude oils or to such averaged prices of crude, fuel oil and gas oil as parameters that determine the price of the LNG. Prices in the Asian market are usually on a CIF basis and have been rather flat over the last 7-8 years, in line with the rather stable (depressed) oil and oil product prices over the same time after the collapse of the oil prices in 1986. In Annex 3.5 an overview is given of CIF prices of LNG, imported by Japan from the Middle East (Abu Dhabi) and of the average Japanese CIF import prices of LNG, both over the period 1981-1991. Recent average import prices of LNG for Japan are in the US$3.1-3.3/mmBtu range, reflecting the somewhat lower oil prices compared with those of the early 1990s. When freight

differentials as between Japan and India are considered, India should be able to secure a lower price than Japan and so too, Pakistan.

4

Organizing and Financing Imports

Issues in Gas Imports[6]

Elements of a contract

Large scale gas import projects, in which the gas is to be transported over a distance of 1,000 km and more, require huge investments, not only in the upstream phase of such projects (which includes the gas production and transmission facilities), but also in the downstream phase where an infrastructure for distribution to industrial and domestic/ commercial gas users is essential. Large gas projects, therefore, require sophisticated contractual arrangements to ensure that the involved parties have a balanced agreement and are able to live up to their commitments over a long time period. The main elements that define the balance of an agreement may be divided into two types: (i) the *commercial or material elements,* which include matters of delivery points, required investments, and quality, quantity and pricing of the gas; (ii) the *technical or practical elements,* which relate to handling of the gas stream, metering, testing, and so on. A full overview is provided in Annex 4.1, where the left hand column shows the *commercial* points that should be covered by the contract, and the right hand column shows the more *technical* considerations.

In respect with quantities, it should be noted that in international pipeline contracts a yearly as well as a daily or hourly maximum and minimum quantity are stipulated, with the purpose to define an steady load of the pipeline system. A typical figure for this load is that it can fluctuate between 80 percent and 120 percent of the averaged yearly load. In addition, economic quantities for long distance pipeline transmission would typically require transporting about 1,500 mmcfd of gas; economic packages for LNG require processing of about 2 million tons LNG per year (in one train of about 300 mmcfd), which in power generation could provide the fuel to a 2,500 MW combined cycle plant.

It may be a good idea to deal with many of the technical or practical elements of a contract in a separate, supplementary document, which can be changed more

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[6]Based upon: R.Dickel: Long term gas contracts, Principles and Applications, and upon: B.Hamso et al.: International Gas Trade, Potential major projects. Both are World Bank publications.

easily than a contract. These supplementary documents may reflect new technical developments, new means of communication, or more advanced metering devices. Experience indicates that amendments to such supplementary agreements are often seen as reasonable and necessary and that they generally do not change the commercial balance of the overall contract.

Risks

Contrary to the marketing of oil, the marketing of gas requires investment in a long-term marketing infrastructure, consisting of a costly transmission and distribution system. The gas producer is thus bound to the customers down the pipeline and vice versa; this implies that in a gas chain, apart from the hydrocarbon reserve risk and the price risk which are also present in the oil chain, there is a potential marketing risk for the producer of the gas. To cope with this additional risk, most international gas contracts contain a *take-or-pay clause,* which stipulates that the buyer commits itself to pay for a substantial part (mostly 80 percent) of the yearly contracted quantity of gas, whether these quantities have been taken or not. Only in cases of force majeure the buyer will be exempted from this obligation. Other risks that govern international gas contracts are political risks and exchange risks, in case the gas is not paid for in hard currency. The political risks may influence the way gas business is conducted. For example, rates of return between 25 percent and 35 percent, and sometimes higher, are common criteria for international companies operating in politically volatile areas; such rates may be double the level, acceptable for gas projects in more secure areas of the world.

All risks, including the political, marketing, exchange and project risks, will have to be shared between the project participants, such as the governments, the project developers, the commercial lenders and the international financial institutions. More specifically, private sponsors are certainly looking for a firm commitment in the form of a Government guaranteed take-or-pay contract. Commercial lenders will also look at such Government's guarantee to protect the stream of revenues of the project. This is understandable when one realizes that a large portion of the imported gas is to be used in power generation which is not viable today without a substantial change in the electricity pricing system. The role of one or more multilateral international institutions would be to minimize the political risk (performance of the gas utilities) and the market risk (back-up of the take-or-pay contract). They are also well-equipped to provide technical assistance and help in the financial structuring of the projects.

Since the investment requirements as well as the political and marketing risks in gas import projects are considerable, participation of international financial institutions in those projects seem essential. They can provide for the development of appropriate security packages and the use of guarantee instruments, such as recently developed by the World Bank. They can also play a major role in facilitating the necessary cooperation among project developers, commercial investors, governments and other major players in the projects.

Organizing Imports

The following discussion takes the case of India as an example. However, the same observations apply equally to Pakistan and the corresponding institutions in that country, such as Pakistan State Oil Limited, Sui Northern Gas Pipelines Limited and Sui Southern Gas Company, and Oil and Gas Development Corporation.

India has an established system for importing crude oil and oil products. This is primarily the responsibility of the Indian Oil Corporation (IOC), a state owned corporation, which is under partial privatization. Having been in the import business for several years, IOC has acquired expertise in international negotiations and trading. IOC has maintained close contacts with the oil exporting countries, the international commercial banks, the domestic financial market and a whole lot of other players in international business. Its own status as a succesful company and a financial giant, with 'Fortune'-listing, gives it a prestige which should be put to use when India launches projects for import of natural gas, which is but an extension of IOC's role as the main importer of oil.

The Gas Authority of India Ltd. (GAIL), also a wholly owned state corporation, has been engaged in marketing domestic gas and operating the HBJ pipeline. In recent times, GOI has called on GAIL and Engineers India Ltd., a state owned corporation for engineering and construction supervision of state projects in the oil and gas sector, to advise it on gas imports.

In major policy shifts, GOI and the State governments have been encouraging the private sector to invest in energy infrastructure projects, both on grounds of speedier execution of such projects and providing investments finances. The ENRON project for power generation in Maharashtra, which is designed to use imported gas in due course, is a major break-through in this respect.

India's own private sector is dynamic in the new economic climate of a near free market. There is a thirst for foreign capital, which too is eager to come to India in its different forms, namely portfolio equity, direct investment, private loans and bonds.

In organizing import of natural gas, each of the advantages as outlined in the preceding paragraphs should be pressed into service. GOI should prepare an indicative plan for import of gas and probably issue a paper. One of the important issues that should be adressed by the Government in preparing the gas import plan is the notion that any gas import scheme cannot easily be implemented without a (dramatic) change in the current energy pricing policies of the country. The system of subsidizing certain energy products should be abolished and a pricing policy, based on sound economic principles, should be put in place[7]. Without undertaking the necessary pricing reforms the market risks of embarking in any gas import scheme are simply too high. For the same reason, the gas allocation policy of the Government should be eliminated. Continuation to allocate gas to uneconomic uses (e.g. as a feedstock for new fertilizer plants) implies continuation of subsidies. In addition, it would be difficult to mobilize resources for the construction of

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[7] It is perhaps useful to notice here that a non-subsidized system of international prices of competing fuels was the basis for assessment of the netback values for gas in its various applications.

transmission and distribution networks if the concerned gas utilities were obliged to supply gas to uneconomic consumers, and if they were not protected by a sound pricing policy.

The gas importing country, in addition, should be aware that it is strategically in a vulnerable position when it becomes overly dependent on a single energy source. For the case of India, it can be seen from Fig. 2.2. that, at least up to the year 2003, the 'energy-mix" for the country is not unbalanced and there exists no excessive dependency on imported energy[8]. Especially for the longer term, when domestic energy sources are becoming more and more depleted, it is important for any energy importing country to have in place an import strategy which assures that there is an adequate diversification of energy supply from foreign sources.

Taking into account what has been stated above, IOC should then move to 'bring into being' the several projects, availing itself of technical assistence from GAIL and EIL. The phrase 'bring into being' is deliberately chosen. IOC should invoke private interest- it is likely to be foreign interest by and large- and limit its own direct implementation of any component of a project to the minimum required for all other pieces to fall into place.

Gas import projects are of two kinds: import by pipelines and import as LNG, and may be arranged in the following modules:

Pipeline imports

(i) Gas production in the exporting country

(ii) Pipeline transportation

(iii) Gas sale in India

Module (i) is the responsability of the exporting country, most likely in a joint venture with one or more international oil companies; the joint venture will raise the finances necessary to develop the gas fields and make the gas available at the pipeline inlet. Module (ii) should be executed by a consortium of mainly foreign companies/investors. Module (iii) will be the responsibility of IOC[9] with the active involvement of GAIL. IOC will negotiate the terms and conditions of the contract to buy stated quantities of natural gas at stated times. Receiving terminals, storage etc., should be provided by IOC. If the supply is to power plants, IOC/GAIL will negotiate the sale in due time, far in advance of contracting for purchase of gas, and ensure that the power plants are installed or ready in time to use the gas. If the supply is to industries or other consumers, IOC/GAIL will ensure that the sale contracts are signed in sufficient advance time and the internal distribution infrastructure is in place. It may be that the consumers will finance the infrastructure, particularly long dedicated pipelines to industrial centers and agree to open access for other consumers to make use of the pipelines at later dates.

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[8]Fig.2.4. shows that the same, though to a lesser extent because its relatively higher import dependency, is true for the case of Pakistan up to the year 2003.

[9] IOC will include GAIL and EIL as necessary.

LNG imports

Under this mode, the modules are the following:

(i) Gas production in the exporting country

(ii) Liquefaction of gas

(iii) Transportation by LNG tankers

(iv) Regassification

(v) Gas sale in India

Modules (i), (ii) and (iii) are likely to go together and lie in the domain of a foreign consortium of companies. Or, one consortium may handle modules (i) and (ii) and another module (iii). IOC would negotiate for purchase of LNG, either on FOB or on CIF basis; in the former case it would also negotiate for transportation. But regassification would be with IOC as also the further sale in India. This would correspond to module (iii) considered under the Pipeline transportation mode.

It may be necessary to develop cross country trunk pipelines, e.g. connecting the existing western system to the southern region of India; this work will fall to GAIL to execute. Procedures as presently obtain for strengthening the HBJ pipeline would apply.

Financing the Projects

The most important challenge in gas import projects is the arrangement of a viable financing scheme. Most common is the "build-own-and-operate" (BOO) scheme, in which private investors mobilize the required capital, build the transmission infrastructure (LNG or pipeline), and operate the system under a take-or-pay contract with a gas company in the importing country. The success of such a scheme would require that:

(i) The private investor has the financial capacity to provide the equity funds of about 25-30 percent of the project cost. In many gas export projects the project cost, excluding the downstream market development, is in the order of US$4-5 billion, implying equity investments of US$1-1.5 billion. Many of the proponents of BOO schemes do not have a financial capacity close to this level.

(ii) An instrument is developed to cope with political risk. Private investors do not enter easily into situations where there is significant political risk. This clearly becomes a more serious consideration when large investments with long gestation periods are at stake. Under these circumstances, a guarantee instrument would economize private sector participation considerably. This kind of instrument can be developed in conjunction with private insurance programs or with multilateral institutions.

Potential financiers of international gas projects will also be greatly encouraged to participate, when most or all of the following conditions are fulfilled as well:

(iii) The project has full political support of the exporting and importing governments, as well as of the governments through whose jurisdictions the gas will be transited.

(iv) The consortium that is launching the project may have to include one or several major international oil or gas companies.

(v) The implementation of the project must be in reputable and experienced hands.

(vi) Long term contracts with unconditional commitments, including take-or-pay clauses, must be signed.

Recommended Strategy

Based on an analysis of the above factors, the tentative recommended strategy for import of gas should incorporate the following:

- *Multiple vs. single gas sources.* A multi-source approach is possible in view of the size of the need for imports of gas of 4,500 mmcfd and would alleviate political risk perceptions.
- *Total investment needs.* The total investment needed for natural gas import should include also the downstream infrastructure necessary to deliver the gas to the consumer.
- *Coordination of supply and demand.* In view of the large investment requirements, both upstream and downstream, graduated market development in phase with the upstream construction is highly desirable. The economies of scale that may be possible through larger upstream systems need to be balanced with the possibilities of asynchrony in the completion of the downstream markets.
- *Allocation and management of risks.* The political, market, commercial and project risks will have to be shared between the governments, the developers and the international financial institutions.
- *International financial institutions participation.* Since both the investment requirements, political and market risks of these projects are so great, the participation of the international financial institutions seems essential. The role of these institutions could be to provide technical assistance, help in the financial structuring of the projects, development of appropriate security packages, and use of guarantee instruments.
- *Lead institutions for project development.* There is a need for clarity in the responsibility and the process for development of a project which is complex, involves a large number of domestic agencies, and is international in scope. The countries could nominate specific agencies to develop specific projects as outlined above, but with an oversight committee for final decisions, within a specified time frame.

Prices of oil products and natural gas in India, Pakistan and OECD-Europe as per 1/1/1993

		India*	Pakistan**	OECD Europe
Automotive:				
regular gasoline	(US cts/litre)	64.5	45.2	n.a.
diesel	(US cts/litre)	21.9	19.6	57.9
Household:				
kerosene	(US cts/litre)	9.4	19.3	36.3
LPG	(US cts/kg)	18.2	20.4	n.a.
Natural gas	(US$/mmBtu)	1.80	1.41	12.33
Industrial:				
Fuel oil, general ind.	(US$/ton)	185.4	91.4	130.9
Fuel oil, fertilizer ind.	(US$/ton)	110.1	91.4	n.a.
Natural gas, general ind.	(US$/mmBtu)	1.80 (coast)	2.12	4.22
		2.73 (HBJ)		
Natural gas, fertilizer ind.	(US$/mmBtu)	1.80 (coast)	0.92	n.a.
		2.73 (HBJ)		

* Bombay-area **Islamabad-area

Sources: The World Bank: -A survey of Asia's Energy Prices
IEA: IEA Statistics, 2nd quarter 1994

INDIA

Coal Production 1980-1992

Year	Production (mmtoe)	Yearly growth(%)
1980-81	55.82	-
1981-82	60.87	9.0
1982-83	63.95	5.1
1983-84	67.73	5.9
1984-85	72.23	6.6
1985-86	75.56	4.6
1986-87	81.23	7.5
1987-88	88.08	8.4
1988-89	95.35	8.3
1989-90	98.44	3.2
1990-91	103.75	5.4
1991-92	112.35	8.3
1992-93	116.72	3.9

Source: CMIE, Current Energy Scene in India, May 1993

Netback value for gas in power generation

For the calculation of the netback value of gas in power generation the following assumptions have been used:

	Oil fired plant	Coal fired plant	CC Gas fired plant
Capacity (MW)	600	600	600
Unit investment cost (US$/kW)	900	1,000	600
Cost contingency (%)	15	15	15
Operational cost (% of investment cost)	2	2.5	4
Fuel efficiency (%)	37	37	45
Cost of coal (US$/mmBtu)	-	1.70	-
Cost of fuel oil (US$/ton)	105	-	-
Construction period of plant	4 years	4 years	4 years
Start of power production	in 4th year	in 4th year	in 4th year
Discount factor (%)	15	15	15

The netback value for gas is calculated as follows:

(1) Calculate the net present value of the total cost (capex, opex and fuel) for oil fired resp. coal fired plant
(2) Calculate the net present value of the cost, excluding fuel (=gas) cost, for the combined cycle plant
(3) Calculate the difference of these two net present values
(4) Divide that difference by the net present value of the quantity of gas that is required in the gas fired plant to generate the same power as the coal fired or oil fired plants
(5) The quotient is the netback value for gas.

GAS VALUE IN POWER

600 MW COAL PLANT,WESTCOAST

Efficiency	37%
Cap'y MW	600
GWh/yr	3993
(at 6655H)	
Unit inv.cost,incl	$1150/kW
15% contingency	
Opex	2.5% of investm.

600 MW C.C. PLANT

Efficiency	45%
Cap'y MW	600
GWh/yr	3993
(at 6655 H)	
Unit inv.cost, inc	$690/kW
15% contingency	
Opex	4% of investm.

	600 MW COAL, WESTCOAST					600 MW COMBINED CYCLE					
	CAPEX incl.cont. (min US$)	FO CONS'N net basis (min MMBtu/Y)	FO COST plant gate (min US$/Y)	OPEX (min US$/Y)	CAPEX+ OPEX (min US$)	CAPEX (min US$)	OPEX (min US$/y)	CAPEX+ OPEX (min US$)	GAS CONS'N (min m3/y)	GAS CONS'N (min m3/d)	GAS CONS'N (min MMBtu/y
1994	104	0	0.00	0	104.00	82	0	82	0	0	0
1995	345	0	0.00	0	345.00	166	0	166	0	0	0
1996	172	0	0.00	0	172.00	104	0	104	0	0	0
1997	69	36.82	62.60	17.3	148.90	62	16.6	78.6	841	2.30	30.30
1998	0	36.82	62.60	17.3	79.90	0	16.6	16.6	841	2.30	30.30
1999	0	36.82	62.60	17.3	79.90	0	16.6	16.6	841	2.30	30.30
2000	0	36.82	62.60	17.3	79.90	0	16.6	16.6	841	2.30	30.30
2001	0	36.82	62.60	17.3	79.90	0	16.6	16.6	841	2.30	30.30
2002	0	36.82	62.60	17.3	79.90	0	16.6	16.6	841	2.30	30.30
2003	0	36.82	62.60	17.3	79.90	0	16.6	16.6	841	2.30	30.30
2004	0	36.82	62.60	17.3	79.90	0	16.6	16.6	841	2.30	30.30
2005	0	36.82	62.60	17.3	79.90	0	16.6	16.6	841	2.30	30.30
2006	0	36.82	62.60	17.3	79.90	0	16.6	16.6	841	2.30	30.30
2007	0	36.82	62.60	17.3	79.90	0	16.6	16.6	841	2.30	30.30
2008	0	36.82	62.60	17.3	79.90	0	16.6	16.6	841	2.30	30.30
2009	0	36.82	62.60	17.3	79.90	0	16.6	16.6	841	2.30	30.30
2010	0	36.82	62.60	17.3	79.90	0	16.6	16.6	841	2.30	30.30
2011	0	36.82	62.60	17.3	79.90	0	16.6	16.6	841	2.30	30.30
2012	0	36.82	62.60	17.3	79.90	0	16.6	16.6	841	2.30	30.30
2013	0	36.82	62.60	17.3	79.90	0	16.6	16.6	841	2.30	30.30
2014	0	36.82	62.60	17.3	79.90	0	16.6	16.6	841	2.30	30.30
2015	0	36.82	62.60	17.3	79.90	0	16.6	16.6	841	2.30	30.30
TOTAL	690	699.62	1189.3	328.7	2208.05	414	315.4	729.4	15972	43.76	575.63
NPV@15%	503.85	150.07	255.11	70.51	829.46	300.65	67.65	368.31	3425.94	9.39	123.47
									Netback versus coal		3.73

GAS VALUE IN POWER

600 MW OIL PLANT		600 MW C.C. PLANT	
Efficiency	37%	Efficiency	45%
Cap'y MW	600	Cap'y MW	600
GWh/yr	3993	GWh/yr	3993
(at 6655H)		(at 6655 H)	
Unit inv.cost,incl	$1035/kW	Unit inv.cost incl	$690/kW
15% contingency		15% contingency	
Opex	2% of investm.	Opex	4% of investm.

	600 MW OIL					600 MW COMBINED CYCLE					
	CAPEX incl.cont. (mln US$)	FO CONS'N net basis (mln MMBtu/y)	FO COST plant gate (mln US$/y)	OPEX (mln US$/y)	CAPEX+ OPEX (mln US$)	CAPEX (mln US$)	OPEX (mln US$/y)	CAPEX+ OPEX (mln US$)	GAS CONS'N (mlm m3/y)	GAS CONS'N (mln m3/d)	GAS CONS'N mln MMBtu/y
1994	124	0	0.00	0	124.00	82	0	82	0	0	0
1995	373	0	0.00	0	373.00	166	0	166	0	0	0
1996	93	0	0.00	0	93.00	104	0	104	0	0	0
1997	31	36.82	92.27	12.4	135.67	62	16.6	78.6	841	2.30	30.30
1998	0	36.82	92.27	12.4	104.67	0	16.6	16.6	841	2.30	30.30
1999	0	36.82	92.27	12.4	104.67	0	16.6	16.6	841	2.30	30.30
2000	0	36.82	92.27	12.4	104.67	0	16.6	16.6	841	2.30	30.30
2001	0	36.82	92.27	12.4	104.67	0	16.6	16.6	841	2.30	30.30
2002	0	36.82	92.27	12.4	104.67	0	16.6	16.6	841	2.30	30.30
2003	0	36.82	92.27	12.4	104.67	0	16.6	16.6	841	2.30	30.30
2004	0	36.82	92.27	12.4	104.67	0	16.6	16.6	841	2.30	30.30
2005	0	36.82	92.27	12.4	104.67	0	16.6	16.6	841	2.30	30.30
2006	0	36.82	92.27	12.4	104.67	0	16.6	16.6	841	2.30	30.30
2007	0	36.82	92.27	12.4	104.67	0	16.6	16.6	841	2.30	30.30
2008	0	36.82	92.27	12.4	104.67	0	16.6	16.6	841	2.30	30.30
2009	0	36.82	92.27	12.4	104.67	0	16.6	16.6	841	2.30	30.30
2010	0	36.82	92.27	12.4	104.67	0	16.6	16.6	841	2.30	30.30
2011	0	36.82	92.27	12.4	104.67	0	16.6	16.6	841	2.30	30.30
2012	0	36.82	92.27	12.4	104.67	0	16.6	16.6	841	2.30	30.30
2013	0	36.82	92.27	12.4	104.67	0	16.6	16.6	841	2.30	30.30
2014	0	36.82	92.27	12.4	104.67	0	16.6	16.6	841	2.30	30.30
2015	0	36.82	92.27	12.4	104.67	0	16.6	16.6	841	2.30	30.30
TOTAL	621	699.62	1753.2	235.6	2609.82	414	315.4	729.4	15972	43.76	575.63
NPV@15%	468.74	150.07	376.06	50.54	895.34	300.65	67.65	368.31	3425.94	9.39	123.47
									Netback versus oil		4.27

INDIA

GAS DEMAND/SUPPLY
(mmcmd)

	1992	1994	1996	1998	2000	2002	2003
Demand High	43.3	62.3	85.0	112.4	148.6	193.3	223.2
Demand Medium	43.3	52.6	65.7	85.5	113.8	153.4	180.3
Supply	43.3	52.6	60.7	67.7	73.1	73.1	73.1

Sources: TERI, Gaffney Cline Associates, World Bank

PAKISTAN
GAS DEMAND/SUPPLY
(mmcfd)

	1992	1994	1996	1998	2000	2002	2003
Demand High	1550	1954	2445	2885	3322	3780	4020
Demand Medium	1550	1914	2275	2645	3016	3420	3635
Supply	1550	1824	2110	2410	2650	2850	2940

Sources: Referenced World Bank Study

Country	Reserves proved and probable	Prominent fields for export to Asia	LNG	Pipeline for export to Asia
Iran	700 Tcf country as a whole	S. Pars and N. Pars offshore undeveloped. Basic designs for developing S. Pars to be prepared by an international engineering company being selected. For N. Pars, desultory negotiations with Shell in progress	No development	IGAT lines to FSU have ceased carrying gas; a study for a pipeline to India is to be taken up, jointly sponsored by India and Iran; also, a feasibility study for a pipeline to Pakistan has been agreed upon between the two governments
Oman	20 Tcf in various fields and of variable quality	Barik, Mabruk, Saih Nihayada and Saih Rawl fields onshore being developed for 6.3 Tcf.	LNG export of 6 mmt to far east planned by a consortium: Government, Shell, Total and Japanese companies; target year; 2000; 7 Tcf dedicated.	Pipeline to India was under consideration-: a shallow water route along Iran & Pakistan continental shelf (one 35" 2000 km) or a direct deep sea route (two 24" 1440 km).The LNG consortium (Oman, Shell, Total and Japanese) apparently feel that the reserves are not adequate for both LNG and the pipeline to India.The latter seems to be on indefinite hold.
Qatar	160 Tcf	Dome field, extension of Iran's S. Pars	Project 1: QGPC, Total, Mobil Marubeni in a consortium committed to supplying Japanese power utilities 4 mmt p.a. starting 1997; a further 2 mmt p.a. available. Project 2: QGPC, Mobil close to agreeing to sell Korea Gas 2.4 mmt p.a. in 1998; Enron in India likely to take 2.5 mmt p.a. in phases from 1998; a further 5.2 mmt p.a. available for negotiation. Project 3: Eurogas Project, 6 mmt p.a. failed due to non-agreement on price with Italy. Project 4: Under discussion with Elf-Sumitomo for 4 mmt p.a.	Brown & Root of USA, TransCanada Pipelines and Crescent Petroleum of the Emirates are sponsoring a pipeline to Pakistan, 1600 km along offshore Iran and Pakistan. Linkage with India envisaged by the sponsors. Capacity 2 bcfd, diameter 40" or more
Turkemenistan	80 Tcf country as a whole	Sovetabad in the south near Iran	Landlocked	Pipeline via Iran and Pakistan possible-onland.
U.A.E.	Substantial		Das Island facility-4.6 mmt p.a. exports done. Further expansion by 2 mmt p.a. practicable, would be economical too.	No pipeline considered.
Yemen	Substantial		Hunt & Exxon have a feasibility study for 5 mmt p.a. But all on hold now.	

		IRAN/QATAR/OMAN - BOMBAY LNG					600 MMCFD			
				EXPENDITURE, MM US$			OPERATING COST, MM US$			
Year	Gas sales	Project tariff	Gross revenue	Liquefac	Ship (2 ships)	Regassification	Liquefac	Ship	Regassification	Net revenue
	MMT p.a.	US$ / MMBtu	MM US$							MM US$
1	0	3.23	0	120	38	34	0	0	0	-192
2	0	3.23	0	320	100	90	0	0	0	-510
3	0	3.23	0	460	150	135	0	0	0	-765
4	0	3.23	0	400	125	112	0	0	0	-637
5	1	3.23	162	280	87	79	0	0	0	-285
6	3	3.23	485	0	0	0	75	37	24	349
7	4	3.23	646	0	0	0	75	37	24	510
8	4	3.23	646	0	0	0	75	37	24	510
9	4	3.23	646	0	0	0	75	37	24	510
10	4	3.23	646	0	0	0	75	37	24	510
11	4	3.23	646	0	0	0	75	37	24	510
12	4	3.23	646	0	0	0	75	37	24	510
13	4	3.23	646	0	0	0	75	37	24	510
14	4	3.23	646	0	0	0	75	37	24	510
15	4	3.23	646	0	0	0	75	37	24	510
16	4	3.23	646	0	0	0	75	37	24	510
17	4	3.23	646	0	0	0	75	37	24	510
18	4	3.23	646	0	0	0	75	37	24	510
19	4	3.23	646	0	0	0	75	37	24	510
20	4	3.23	646	0	0	0	75	37	24	510
21	4	3.23	646	0	0	0	75	37	24	510
22	4	3.23	646	0	0	0	75	37	24	510
23	4	3.23	646	0	0	0	75	37	24	510
24	4	3.23	646	0	0	0	75	37	24	510
25	4	3.23	646	0	0	0	75	37	24	510
26	4	3.23	646	0	0	0	75	37	24	510
27	4	3.23	646	0	0	0	75	37	24	510
28	4	3.23	646	0	0	0	75	37	24	510
29	4	3.23	646	0	0	0	75	37	24	510
				1,600	500	450	1,800	888	576	9,690
		At overall tarif								
		of 3.23/MMbtu							IRR	15.00
		Liq 1.98	61%							
		Ship .69	21%							
		Regas .56	18%							
		If liquefaction	investm.=3/4	,then tariff =	US$2.83/ MM	Btu at irr=.15				
		If liquefaction	investm.=1/2	,then tariff =	US$2.43/ MM	Btu at irr=.15				

		IRAN/QATAR/OMAN - KARACHI LNG			15,000 MMCFD					
				EXPENDITURE, MM US$			OPERATING COST, MM US$			
Year	Gas sales	Project tariff	Gross revenue	Liquefac	Ship	Regassification	Liquefac	Ship	Regassification	Net revenue
					(4 a 125.000)					
	MMT p.a.	US$ / MMBtu	MM US$		(1 a 90.000)					MM US$
1	0	2.70	0	300	91	60	0	0	0	-451
2	0	2.70	0	800	240	160	0	0	0	-1,200
3	0	2.70	0	1,200	360	240	0	0	0	-1,800
4	0	2.70	0	1,000	300	200	0	0	0	-1,500
5	4	2.70	540	700	209	140	0	0	0	-509
6	8	2.70	1,080	0	0	0	180	88	40	772
7	11	2.70	1,485	0	0	0	180	88	40	1,177
8	11	2.70	1,485	0	0	0	180	88	40	1,177
9	11	2.70	1,485	0	0	0	180	88	40	1,177
10	11	2.70	1,485	0	0	0	180	88	40	1,177
11	11	2.70	1,485	0	0	0	180	88	40	1,177
12	11	2.70	1,485	0	0	0	180	88	40	1,177
13	11	2.70	1,485	0	0	0	180	88	40	1,177
14	11	2.70	1,485	0	0	0	180	88	40	1,177
15	11	2.70	1,485	0	0	0	180	88	40	1,177
16	11	2.70	1,485	0	0	0	180	88	40	1,177
17	11	2.70	1,485	0	0	0	180	88	40	1,177
18	11	2.70	1,485	0	0	0	180	88	40	1,177
19	11	2.70	1,485	0	0	0	180	88	40	1,177
20	11	2.70	1,485	0	0	0	180	88	40	1,177
21	11	2.70	1,485	0	0	0	180	88	40	1,177
22	11	2.70	1,485	0	0	0	180	88	40	1,177
23	11	2.70	1,485	0	0	0	180	88	40	1,177
24	11	2.70	1,485	0	0	0	180	88	40	1,177
25	11	2.70	1,485	0	0	0	180	88	40	1,177
26	11	2.70	1,485	0	0	0	180	88	40	1,177
27	11	2.70	1,485	0	0	0	180	88	40	1,177
28	11	2.70	1,485	0	0	0	180	88	40	1,177
29	11	2.70	1,485	0	0	0	180	88	40	1,177
TOTALS	265		35,775	4,000	1,200	800	4,320	2,112	960	22,383
		At overall tariff								
		of 2.70/MMbtu							IRR	14.99
		Liq 1.76	65%							
		Ship .59	22%							
		Regas .36	13%							
		If liquefaction	investm.=3/4	,then tariff =	US$2.34/ MM	Btu at irr=.15				
		If liquefaction	investm.=1/2	,then tariff =	US$1.98/ MM	Btu at irr=.15				

TURKMENIA-AHMEDABAD(INDIA) PIPELINE ECONOMIC ANALYSIS						
Year	Gasvolume	Pipeline-tariff	Gross revenue	Investment	Operat. cost	Net revenue
	Bcf p.a.	$/MMBtu	MM US$	MM US$	MM US$	MM US$
1	0	2.51	0	576	0	-576
2	0	2.51	0	1,388	0	-1,388
3	0	2.51	0	1,759	0	-1,759
4	0	2.51	0	1,062	0	-1,062
5	132	2.51	338	294	47	-3
6	265	2.51	678	294	65	319
7	397	2.51	1,016	147	110	759
8	529	2.51	1,354	0	143	1,211
9	529	2.51	1,354	0	143	1,211
10	529	2.51	1,354	0	143	1,211
11	529	2.51	1,354	0	143	1,211
12	529	2.51	1,354	0	143	1,211
13	529	2.51	1,354	0	143	1,211
14	529	2.51	1,354	0	143	1,211
15	529	2.51	1,354	0	143	1,211
16	529	2.51	1,354	0	143	1,211
17	529	2.51	1,354	0	143	1,211
18	529	2.51	1,354	0	143	1,211
19	529	2.51	1,354	0	143	1,211
20	529	2.51	1,354	0	143	1,211
21	529	2.51	1,354	0	143	1,211
22	529	2.51	1,354	0	143	1,211
23	529	2.51	1,354	0	143	1,211
24	529	2.51	1,354	0	143	1,211
25	529	2.51	1,354	0	143	1,211
26	529	2.51	1,354	0	143	1,211
27	529	2.51	1,354	0	143	1,211
28	529	2.51	1,354	0	143	1,211
29	529	2.51	1,354	0	143	1,211
Total	12,432		31,828	5,520	3,368	22,940
NPV @ 15%	1,594		4,081	3,643	435	
					IRR	15.01

QATAR-AHMEDABAD(INDIA)ONSHORE PIPELINE ECONOMIC ANALYSIS						
Year	Gasvolume	Pipeline-tariff	Gross revenue	Investment	Operat. cost	Net revenue
	Bcf p.a.	$/MMBtu	MM US$	MM US$	MM US$	MM US$
1	0	2.44	0	618	0	-618
2	0	2.44	0	1,236	0	-1,236
3	0	2.44	0	1,590	0	-1,590
4	0	2.44	0	1,114	45	-1,159
5	132	2.44	329	290	70	-31
6	265	2.44	660	290	110	260
7	397	2.44	988	142	136	710
8	529	2.44	1,317	0	136	1,181
9	529	2.44	1,317	0	136	1,181
10	529	2.44	1,317	0	136	1,181
11	529	2.44	1,317	0	136	1,181
12	529	2.44	1,317	0	136	1,181
13	529	2.44	1,317	0	136	1,181
14	529	2.44	1,317	0	136	1,181
15	529	2.44	1,317	0	136	1,181
16	529	2.44	1,317	0	136	1,181
17	529	2.44	1,317	0	136	1,181
18	529	2.44	1,317	0	136	1,181
19	529	2.44	1,317	0	136	1,181
20	529	2.44	1,317	0	136	1,181
21	529	2.44	1,317	0	136	1,181
22	529	2.44	1,317	0	136	1,181
23	529	2.44	1,317	0	136	1,181
24	529	2.44	1,317	0	136	1,181
25	529	2.44	1,317	0	136	1,181
26	529	2.44	1,317	0	136	1,181
27	529	2.44	1,317	0	136	1,181
28	529	2.44	1,317	0	136	1,181
29	529	2.44	1,317	0	136	1,181
Total	12,432		30,941	5,280	3,353	22,308
NPV @ 15%	1,594		3,967	3,477	484	
					IRR	15.02

		INDIA : AHMEDABAD-COCHIN TRANSPORT OF NATURAL GAS (1560 KM.)						
YEAR	INVESTMENT	MAINTENANCE	GASVOLUME	GASVOLUME	GASVOLUME	TARIFF	REVENUES	NET BENEFIT
	$ million	$ million	mmcfd	bcm	mln mmBtu	$US /mmBtu	$ million	$ million
1	300							-300.00
2	600							-600.00
3	1550							-1550.00
4	625							-625.00
5		65	1500	15.49	553	1.14	630.84	565.84
6		65	1500	15.49	553	1.14	630.84	565.84
7		65	1500	15.49	553	1.14	630.84	565.84
8		65	1500	15.49	553	1.14	630.84	565.84
9		65	1500	15.49	553	1.14	630.84	565.84
10		65	1500	15.49	553	1.14	630.84	565.84
11		65	1500	15.49	553	1.14	630.84	565.84
12		65	1500	15.49	553	1.14	630.84	565.84
13		65	1500	15.49	553	1.14	630.84	565.84
14		65	1500	15.49	553	1.14	630.84	565.84
15		65	1500	15.49	553	1.14	630.84	565.84
16		65	1500	15.49	553	1.14	630.84	565.84
17		65	1500	15.49	553	1.14	630.84	565.84
18		65	1500	15.49	553	1.14	630.84	565.84
19		65	1500	15.49	553	1.14	630.84	565.84
20		65	1500	15.49	553	1.14	630.84	565.84
21		65	1500	15.49	553	1.14	630.84	565.84
22		65	1500	15.49	553	1.14	630.84	565.84
23		65	1500	15.49	553	1.14	630.84	565.84
24		65	1500	15.49	553	1.14	630.84	565.84
25		65	1500	15.49	553	1.14	630.84	565.84
26		65	1500	15.49	553	1.14	630.84	565.84
27		65	1500	15.49	553	1.14	630.84	565.84
28		65	1500	15.49	553	1.14	630.84	565.84
29		65	1500	15.49	553	1.14	630.84	565.84
Total	3075	1625	37500	387.36	13834		15770.93	11070.93
							IRR	15.00

Annex 3.4

Prices of LNG for Japan

(CIF, US$/mmBtu)

Year	Average LNG price	Abu Dhabi LNG price
1981	5.83	6.61
1982	5.74	6.27
1983	5.16	5.47
1984	4.90	5.21
1985	4.99	4.89
1986	3.98	4.37
1987	3.29	3.29
1988	3.22	3.19
1989	3.26	3.09
1990	3.60	3.29
1991	3.98	3.90
First half of 1994	3.09	3.11

Source: Cedigaz World LNG trade

Commercial versus Technical Elements of a Contract

Commercial/Material	Technical
Delineation of spheres	
Define delivery point(s)	Handling of gas streams
Investment to realize the project	
Define investment obligation of both sides	
Quantity	
Commitments Sharing of risks Exceptions (force majeure) Penalty/incentive schemes	Metering, operating rules, Information flow
Quality	
Specification	Specification definition
Consequences, if offspec	Applicable test information on quality
Price	
Determination of price formula	Billing and payment rules
Due date of payment Minimum pay price, default rebates Taxes Currency Review of the price formula	
Information	
Scope of information to be given to the other side	Means of communication