UNIVERSITY OF PETROLEUM AND ENERGY STUDIES

A FINAL DISSERTATION REPORT ON

NATURAL GAS SCENARIO – DEMAND & SUPPLY, RISK & OPTIONS.

(MODEL DEVELOPMENT THAT ABLE TO FORECAST THE FUTURE DEMAND NATURAL GAS)

Submitted by

Purnesh Meshram

M.Tech – Gas Engineering

(Year 2004-06)

Under the Guidance of

Dr.R.P. Badoni

Distinguish Professor.

(Mtech. Coordinator)

UPES, Dehradun.

An Internship report submitted in partial fulfillment of the requirements for Masters of Technology (Gas Engineering)

University of Petroleum & Energy Studies

College of Engineering

Village& Post - Bidholi, via Prem Nagar

Dehradun - 248007

CERTIFICATE

15th May 2006

This is to certify that the project report on "**NATURAL GAS SCENARIO-DEMAND AND SUPPLY, RISK AND OPTIONS. (MODEL DEVELOPMENT THAT ABLE TO FORECAST THE FUTURE NATURAL GAS DEMAND)**", submitted to University of Petroleum & Energy Studies, Dehradun, by **Mr. PURNESH MESHRAM**, in partial fulfillment of the academic requirement for the award of Post Graduate Degree in "M.Tech in Gas Engineering", is a bonafied work carried out by him under my supervision and guidance. This work has not been submitted anywhere else for any other degree.

R.P. Badoni
Mar 18, 2006

Dr. R.P. BADONI
Distinguish Professor
M. Tech Co-ordinator
College of Engineering
UPES, Dehradun.

Project report on

NATURAL GAS SCENARIO –
DEMAND & SUPPLY, RISK & OPTIONS
(MODEL DEVELOPMENT THAT ABLE TO FORECAST THE FUTURE DEMAND)

Table of content

Acknowledgement

The report, which I have made, will not at all possible without the involvement of large number of discussion of the research topic with my classmates, my room mates & teachers. Their contribution, while the preparation of this research work is unforgettable.

Me and all my roommate's (student of B.tech, M.tech & MBA) had discussed this topic many time and at many instances. At the start of this work we thought that the topic is really, really a fish of my own tank and whenever I need I can have a nice dinner or lunch of it, but as we move forward, we realize the real complexity in doing this research work. "NATURAL GAS SCENARIO", it need a level of thinking that I don't feel myself a perfect man right now to do, it required an highly experienced human who can understand all the related topic like Energy Security, impact of Oil prices, other fuels resources and its economy, Indian economy and its background, impact of world scenario, environment of our home planet, India's increasing role in world's tussle cases and impact of this role on its future etc, etc so many related topics, its easy to find out these topics but the real task live with the interconnectivity of all these topics with each other .

I am really thankful to all the information center like Ernst & Young, Mackenzie, KPMG, MOP&N, Price water cooper house, Crisil, TERI, IEA, MOP, MOF, Hydrocarbon Vision 2025 and many other related papers, literature, journals like Dew, Asia oil and Gas, Petrobazar etc. And website and news papers such as Times of India, Business Line, Economics Times, Hindustan Times which provide guidance to me.

I am also thankful to my guide Dr.Badhoni for his guidance without which it being just a painting without colour. I again thankful to Indranil Guha, Deepak Sukla, Prashant, Dhiraj Sinha, Vineet and a very special thanks to Varun Birthier for his computer.

At last I am very much thankful to all sources from where or with whom I directly or indirectly consult for the making of ***"NATURAL GAS SCENARIO- DEMAND AND SUPPLY, OPTIONS AND RISK, MODEL OF NATURAL GAS DEMAND SCENARIO".***

From the heart of creator.

Concerns have been raised about the capacity for INDIA's natural gas supplies to keep pace with growing demand, particularly in Western INDIA. In particular, it has been suggested that unless significant infrastructure investment is undertaken now the demand/supply balance situation in India will deteriorate quickly as natural gas resources are depleted in the face of strongly growing demand.

The purpose of this study is to examine this issue and focuses on whether supplies in India are likely to fall short of growing demand; what is the potential for India to fuel this demand; and if required, what are the other ways to fuel this growing demand and the potential to supply western & northern markets from southern & eastern supplies, mainly from KG basin.

A modeling framework was developed to examine these issues at a national level and forecast the DEMAND-SUPPLY SCENARIO of gas by 2050 off coarse Indian energy experts have already did for 2025 through Hydrocarbon Vision 2025. International issues have been also considered, as India wants to get natural gas from across the boundaries of it. Model is actually based on a known GDP & population growth scenario. The modeling Framework includes representations of all potential sources of natural gas in India by basin and coal seam methane & hydrates, all existing and proposed LNG terminal & pipeline options as well as regional gas demands, by industry.

Chapter 1:"Economy Energy and Natural Gas" deals with the Indian economic review. Relating economy with energy and finally try to find out why natural gas is an important commodity for economy like India.

Chapter 2: "Natural Gas-An world outlook", it present the world natural gas scenario so one can easily recognized the natural gas industry worldwide and its stand.

Chapter 3: "Natural gas Demand Sector's in India", focus on the demand sectors of natural gas.

Chapter 4: "Natural Gas: Supplies", this chapter deals with the supplies of natural gas, indigenous or imported, to fuel the increasing gas demand. Also talks about Pipeline and LNG project status in India.

Chapter 5: "LNG v/s Pipeline- Options and Risk", compare both the available option in Indian scenario by using some international practices.

Chapter 6: "Forecasting and Model", this one is the main chapter in this research topic as it contain the model that has developed by me and forecast the natural gas demand for year 2050.

Chapter 7: "the End Statement", concluded the whole research work based on the above all chapters.

Chapter 1

Economy, Energy and Natural Gas.

HIGHLIGHTS
➢ Indian GDP is growing at 7%. ➢ Population will be 1468 million by 2031-32 & GDP will be 5.5 times of what is today. ➢ Four to five –fold growth in energy consumption to maintain this growth trend. ➢ Electricity demand will grow from 633 Bkwhr to over 3000 Bkwhr. ➢ Natural gas constitute 8% of total energy mix and will gone up 20 %increasing its demand from 155 MMSCMD to 391 MMSCMD. ➢ Indigenous production of gas is 90 MMSCMD. ➢ The availability of natural gas for market including what we are importing by LNG is only about 83 MMSCMD as against the demand of 155.

1.1 Indian economy and world.

India became the fastest growing free-market democracy in the world. India's growth has averaged more than 8 per cent over the past three years driven by broad-based domestic demand and expensive business dynamics.

1. **Agriculture** grew by 9.1% in the year, after notching up 16.5% and 10.5% in the 3rd and the 4th quarters, respectively.
2. **Manufacturing**, which had posted a healthy 6.7% rise in 2002-03,grew by 7.3% in 2003-04.

3. **Other sectors** with more than 5% growth included electricity, gas and water supply (5.5%); construction (6.2%); trade, hotels, transport, real estate and business services (6.8%); community, social and personal services (6%).
4. **Foreign exchange** reserves have grown to over US$ 141 billion (April 2006)

Dreaming with BRICs: The Path to 2050, a Goldman Sachs Report published in 2003, states that at present rates of growth, the burgeoning market in the country "would be adding nearly one France every three and a half years and one Australia every year."

Engines of Economic Growth are many some of them are:

1. Educational levels are rising rapidly.
2. Rates of technological innovation and application are accelerating.
3. Cheaper and faster communication is dissolving physical and social barriers, both within the country and internationally.
4. Information is being made available in greater quantity and quality than ever before.
5. Globalization is opening up new markets.

India's progress over the next 20 years will be intimately linked to events within the region and around the world. The World Bank estimates that India will become the fourth largest economy in the world by 2020. Liberalization of trade will open up new opportunities for export of goods, while increasing pressures on domestic industry to cope with competition from imports. The global market for textiles, clothing and agricultural products will expand dramatically, but India's ability to export will depend on its capacity to keep pace with rising international standards of price, quality, productivity, and service. The

Associated Chambers of Commerce and Industry of India (ASSOCHAM) has projected that by 2010, India's GDP will be doubled with its size touching to US $ 1100 billion from current level of US$ 550 billion, since an average Indian will be growing richer with its per capita income ballooning to US$ 1200 per annum from present level of US$ 600 per annum.

The factors behind the projected phenomenal GDP and Indian's per capita income growth as per findings of ASSOCHAM will be that in next 4-5 years, the productivity and efficiency of Indian ports will not only enhance tremendously but its agricultural growth and irrigation patterns will also witness extensive modernization.

In addition, the GDP investment ratio, which currently is estimated at 30%, will move on by 5%, thus touching a percentage level of 35% by 2010. India's existing labor laws, transport system and irrigation pattern are inadequate and restrain GDP performance by 2 per cent, the study said, adding that in the next 4-5 years Indian ports, agriculture and irrigation patterns will witness extensive modernization, the study on Future's GDP Projections said.

India has the potential to attract 50 billion dollars FDI in the next five years. Current FDI flows into India are 0.8 per cent of GDP, it said.

The overall infrastructural facilities will turn much better than now and contribute substantially to the growth of not only India's GDP but Indians per capita income also.

Heralded as the Best Country to be an Investor in by Newsweek in July 2004,India is likely to emerge as one of the largest consumer markets in the world. On an average, 30-40 million join the consuming class every year. Political empowerment and economic trickle-down have now fuelled ambitions and aspirations in more Indians than in any other period of history. "India's model should prove more sustainable than the typical East Asian strategy adopted by China. India is developing more efficient corporates, healthier banks, more robust service industries and a bigger consumption base", reported Dan Fineman in an April 2004 article in the Far Eastern Economic Review titled Growth Model. In 2003, Indian companies had a higher return on equity than firms in China.

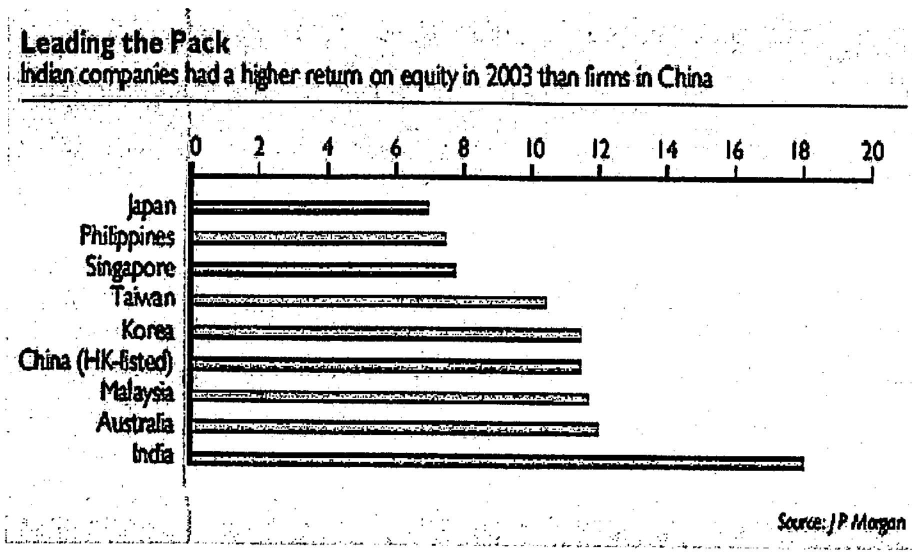


Figure 1 Equity return for MNC's and Indian companies.
Source :

The growing influence of these factors, acting on the foundation of India's increasingly dynamic and vibrant economic base, lend credence to the view that India can achieve and sustain higher than historical rates of economic growth in the coming decades. The compounded effect of achieving the targeted annual GDP growth rate of 8.5 to 9 per cent over the next 20 years and with population growth slowing now to about 1.6 per cent per annum, a growth rate of the gross domestic product (GDP) of around 9 per cent per annum would be sufficient to quadruple the per capita income by 2020,result in a quadrupling of the real per capita income and almost eliminating the percentage of Indians living below the poverty line. This will raise India's rank from around 11th today to 4^{th} from the top in 2020 among 207 countries given in the World Development Report in terms of GDP. Further, in terms of per capita GDP measured in ppp India's rank will rise by a minimum of 53 ranks from the present 153 to 100. This will mean, India will move from a low-income country to an upper middle-income country. This is a very real possibility for us to seize upon and realize. By 2020, the people of India will be more numerous, better educated, healthier and more prosperous than at any time in our long history. Thus we not only believe but its true that we are growing faster in the universe & fastest in the earth.

1.2 INDIAN ECONOMY AND ENERGY RELATION.

The reforms initiated in India since the beginning of the nineties have led to rapid economic progress and better growth rates. In the first decade of this century the growth rates seem to be still better. Studies by several academics and consultants forecast continued high growth rate for the next several decades. I'll quote two such studies, one by Dominic Wilson and Roopa Purushothaman of Goldmann Sachs [1] and the other by Dani Rodrik and Arvind Subramanian of the International Monetary Fund [2].

Wilson and Purushothaman write, "India has the potential to show the fastest growth over the next 30 to 50 years. Growth rate could be higher than 5 percent over the next 30 years and close to 5 percent as late as 2050 if development proceeds successfully." Rodrik and Subramanian write, " growth in capital stock together with growth in factor productivity will yield output growth of 5.4 percent. Over the next 20 years, the working age population is projected to grow at 1.9

percent per year. If educational attainment and participation rates remain unchanged, labor growth will contribute another 1.3 percent, yielding an aggregate growth rate of 6.7 percent per year, or a per capita growth rate of 5.3 percent. This is a lower bound estimate and, even so, would be significantly greater than the per capita growth rate of 3.6 percent achieved in the 1980s and 1990s. Over a 40-year period, a 5.3 percent growth rate would increase the income of the average person nearly 8-fold." Growth in economy is made possible by several inputs, *the two most important being energy and human resource*. In this report, I am concerned about energy and so I'll confine myself to energy.

Energy is the engine for growth. It multiplies human labour and increases productivity in agriculture, industry as well as in services. To sustain the growth rate in economy, energy supply has to grow in tandem. For a large country like India with its over one billion population and rapid economic growth rate, no single energy resource or technology constitutes a panacea to address all issues related to availability of fuel supplies, environmental impact, particularly, climate change, and health externalities. Therefore, it is necessary that all non-carbon emitting resources become an integral part of an energy mix – as diversified as possible – to ensure energy security to a country like India during the present century. Available sources are low carbon fossil fuels, renewables and nuclear energy and all these should be subject of increased level of research, development, demonstration and deployment.

Energy intensity of GDP, defined as the ratio of the energy consumption to the GDP, has been observed to follow a certain trend worldwide. Below a certain level of development, growth results in increase in energy intensity. With further growth in economy, the energy intensity starts declining. Based on data by International Energy Agency [4], overall energy intensity of GDP in India is the same as in OECD countries, when GDP is calculated in terms of the purchasing power parity (PPP). Energy-GDP elasticity, the ratio of the growth rates of the two, remained around 1.3 from early fifties to mid-seventies. Since then it has been continuously decreasing. Electricity is the most important component of the primary energy. Electricity-GDP elasticity was 3.0 till the mid-sixties. It has also decreased since then. Reasons for these energy–economy elasticity changes are: demographic shifts from rural to urban areas, structural economic changes towards lighter industry, impressive growth of services, increased use of energy efficient devices, increased efficiency of conversion equipments and inter-fuel substitution with more efficient alternatives. Based on the CMIE data [5], the average value of the Electricity-GDP elasticity during 1991-2000 has been calculated to be 1.213 and that of the primary energy- GDP elasticity to be 0.907. Estimating the future GDP growth rates of India from the projections made by Dominic Wilson and Roopa Prushothaman [1], taking the primary energy intensity fall to be 1.2 percent per year [6], extrapolating the electricity intensity fall from past data till 2022 and subsequently a constant fall of 1.2 percent year, the growth rates of the primary energy and electrical energy have been estimated as follows.

Period	Primary Energy Percent Annual Growth	Electricity Percent Annual Growth
2002-2022	4.6	6.3
2022-2032	4.5	4.9
2032-2042	4.5	4.5
2042-2052	3.9	3.9

Table . 1. Primary energy growth rate and electricity % annual growth,
Source: Department of Atomic Energy, Govt. of India.

These rates are the basis of the projections reported [3]. It may be recalled that historical primary energy and electricity growth rates during 1981- 2000 were 6 percent per year and 7.8 percent per year respectively.

Based on the growth rates given in the above table, per capita electricity generation would reach about 5300 kWh per year in the year 2052 and total about 8000 TWh. This would correspond to an installed capacity of around 1300 GWe. Annual primary energy consumption would increase from about 13.5 EJ in 2002-03 to about 117 EJ in 2052-53. By then the cumulative energy expenditure will be about 2400 EJ.

	Amount	Thermal energy			Electricity potential
		EJ	TWh	GWYr	GWe-Yr
Fossil					
Coal	38 -BT	667	185,279	21,151	7,614
Hydrocarbon	12 -BT	511	141,946	16,204	5,833
Non-Fossil					
Nuclear					
Uranium-Metal	61,000 -T				
In PHWRs		28.9	7,992	913	328
In Fast breeders		3,699	1,027,616	117,308	42,231
Thorium-Metal	2,25,000 -T				
In Breeders		13,622	3,783,886	431,950	155,502
Renewable					
Hydro	150 -GWe	6.0	1,679	192	69
Non-conventional renewable	100 -GWe	2.9	803	92	33

Table .2. The present status of various fuel-resources in India,
Source: Department of Atomic Energy, Govt. of India.

The domestic mineable coal (about 38 BT) and the estimated hydrocarbon reserves (about 12 BT) together may provide about 1200

EJ of energy. To meet the projected demand of about 2400 EJ, one has to tap all options including using the known fossil reserves efficiently, looking for increasing fossil resource base, competitive import of energy (including building gas pipe lines whenever and wherever permitted based on geo-political considerations and found feasible from techno-commercial considerations), harnessing full hydro potential for generation of electricity and increasing use of non-fossil resources including nuclear and non-conventional.

The Indian population corresponds to one sixth of world population. However, the carbon dioxide emission from India is only around 4% of the global emissions. On the basis of current energy mix and the present day technologies for electricity production, the CO_2 emission from India alone could become as much as half of the present level of global emission in a few decades from now. A larger share of nuclear power & environ friendly fuels in India beyond what would be realized through indigenous efforts would, in principle, contribute to further avoidance of CO_2 emission which otherwise would be inevitable.

Per capita consumption of energy in India is one of the lowest in the world. India consumed 520 kg. of oil equivalent (kgoe) per person of primary energy in 2003 compared to 1090 kgoe in China and the world average of 1,688 kgoe. The consumption in US was 7,835 kgoe per person. India's energy use efficiency for generating GDP in Purchasing Power Parity (PPP) terms is better than the world average, China and the US. (See *Table 2*). However, it is some 50% higher than Denmark and 50% higher than UK, Japan & Brazil. Clearly, significant reduction in the energy intensity of growth can be achieved based on existing technologies

Region/Country	GDP Per Capita-PPP (US $ 2000)	TPES Per Capita (kgoe)	TPES /GDP (Kgoe/$-2000 PPP)	Electricity consumption per capita (kWh)	kWh/$-2000 PPP
China	4838	1090	0.23	1379	0.29
Australia	28295	5630	0.20	10640	0.38
Brazil	7359	1094	0.15	1934	0.26
Denmark	29082	3852	0.13	6599	0.23
Germany	25271	4210	0.17	6898	0.27
India	**2732**	**520**	**0.19**	**435**	**0.16**
Indonesia	3175	753	0.24	440	0.14
Netherlands	27124	4983	0.18	6748	0.25
Saudi Arabia	12494	5805	0.46	6481	0.52
Sweden	27869	5751	0.21	15397	0.55
United Kingdom	26944	3906	0.14	6231	0.23
United States	35487	7835	0.22	13066	0.37
Japan	26636	4052	0.15	7816	0.29
World	7868	1688	0.21	2429	0.31
TPES: Total Primary Energy Supply					

Table 3: ***Selected Energy Indicators for 2003,***

Source: IEA (2005), *Key World Energy Statistics 2005*, International Energy Agency, Paris,http://www.iea.org

The level of per capita Energy Consumption is a good indicator of the level of economic development as seen from *Figure 1* where per capita energy consumption is plotted against per capita Gross Domestic Product (GDP).

Total Primary Energy Supply (TOE) Per Capita (2003) vs. GDP Per Capita (PPP USS2000)

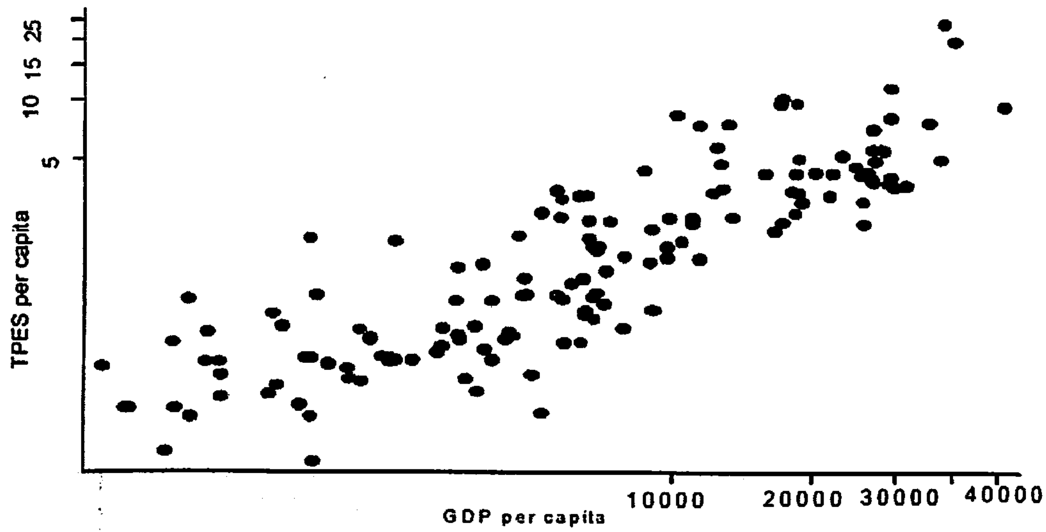


Figure 1. Total Primary Energy Supply (toe) Per Capita (2003) vs. per Capita (ppp USD 2000). Source: IEA 2005 data.

Kilo Watt Hours of Electricity Per Capita vs. GDP Per Capita (PPP US$2000)

Figure 2. KilowattHours of Electricity Per Capita vs. GDP Per Capita (PPP USD2000), Source: IEA 2005 data.

If we look at the consumption of electricity, one of the most convenient forms of energy, we see that per capita consumption in India is way below that in other countries. Moreover, access to electricity is very uneven. Even though 85 percent of villages are considered electrified, around 57 percent of the rural households and 12 percent of the urban households i.e., 84 million households in the country (over 44.2% of households) did not have electricity in 2000. Improvement in human development is also strongly associated with access to electricity. In *Figure 3*, the Human Development Index (HDI), which is calculated from literacy rate, infant mortality rate and per capita GDP (UNDP, 2004) is plotted against per capita electricity consumption.

Human Development Index (HDI) vs. Electricity Consumption Per Capita in 2002

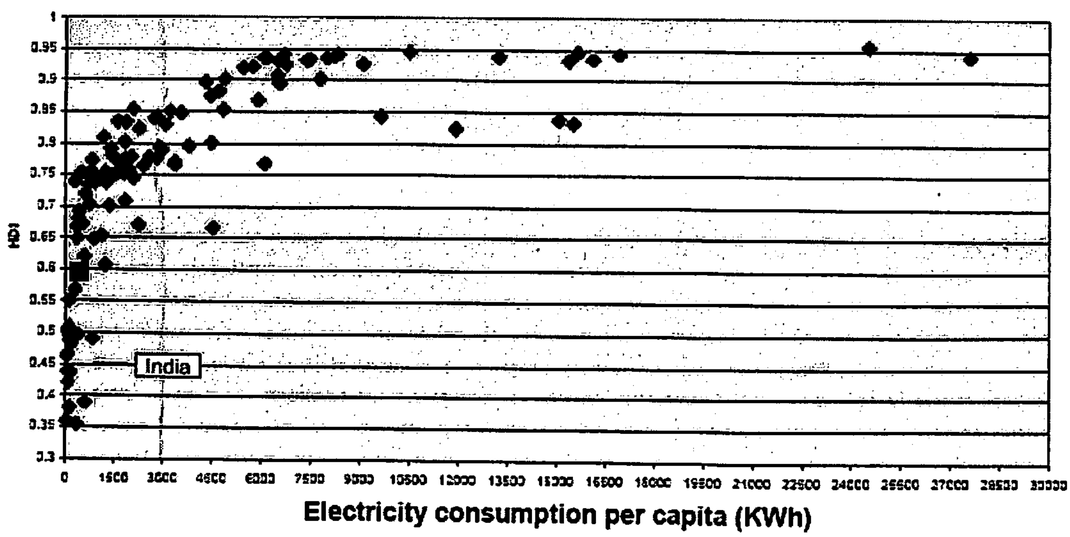


Figure 3 Note: HDI for India 0.595 and Electricity per capita consumption 561 kWhrs. *Sources: United Nations Development Programmer (UNDP-2004) and IEA (2004).*

Power generation in India was only 4.1 billion kWh in the year 1947-48 and in the year 2002-03 it was more than 600 billion kWh. Considering the past record, the future economy growth scenario and likely boost to captive power plant sector as a result of changes arising due to Electricity Act 2003, the target of generating about 8000 billion kWh per year by 2052 is achievable.

While energy security has always been a key concern in all countries, nations have become increasingly conscious of the challenge of ensuring that the growth of the sector in an environmentally benign manner.

Some forecast of energy and economic growth's of India.

The Energy and Resources Institute (TERI), carried out an analysis of the Indian energy scenario and suggested strategies for sustainable development. In their base case scenario the primary energy growth rate was taken as 4.4%/yr during the period 1997-2019 and 3.6%/yr during the period 2020-2047. For electricity, the corresponding growth rates were 5.7%/yr and 3.9%/yr. In the alternative scenario, growth rates are smaller, 3.7%/yr and 3.0%/yr for the primary energy and 5.1%/yr and 3.4%/yr for electricity. Both of these scenarios assume a very large dependence on imports, which is projected to increase from about 20% in the year 1997 to about 70% in the year 2047 in the base scenario and 60% in the alternative scenario.

The International Energy Outlook 2002 (IEO) of the United States predicts for India a reference primary energy consumption growth rate of 3.6%/yr during the period 1997 to 2020. The high and low growth scenarios correspond to 4.5%/yr and 2.6%/yr respectively. For the electricity consumption, the three corresponding growth rates for the above period are 3.8%/yr, 4.5%/yr and 2.6%/yr. Under the project "A Long-term Perspective on Environment and Development in the Asia-Pacific Region" of the Environment Agency of the Government of Japan the primary energy consumption growth rates, for India, were projected to be 3.9%/yr till the year 2025, 2.6%/yr till the year 2050 and 1.8%/yr till the year 2100 under their high estimate category. Similar growth rates have been assumed for India in another study "US-Japan Energy Cooperation to Help Achieve Sustainable Development in Asia".

The primary and electricity energy growth rate forecasts made by the Institute of Energy Economics of Japan (IEEJ), for India, are 5.2%/yr and 5.4%/yr respectively for the forthcoming twenty years.

The Royal Society and The Royal Academy of Engineers of the United Kingdom in their study on the role of nuclear energy in generating electricity have referred to Morrison's projections of world energy requirement. For the developing nations, those are based on 4%/yr until the year 2026, 3%/yr until the year 2050 and 2%/yr for the rest of the century.

In India, Central Electricity Authority (CEA) undertakes periodic electric power surveys (EPS) to make projections of the energy requirements of the country. These estimates guide the planning process for the capacity additions. CEA released its report on the 16th electric power survey in January 2001 and projected electricity growth requirement, for the period 1997-2012, to be about 6.5%/yr and 7.4%/yr in its two scenarios.

Beyond the year 2050, most of the energy growth forecasts are around 1 to 2%/yr.

1.3 INDIAN ENERGY AND ENERGY MIX.

Energy is a basic requirement for economic growth and social development and essential for all life-sustaining activities. The Indian economy has been on a long-term growth trend since the last decade and the GDP growth last year was around 7%. Global experience demands the energy market to keep pace with the growth of economy. Therefore, the key issues of concern today are energy efficiency and availability of oil and gas besides energy-giving constituents like coal, bio fuels, solar energy and other resources. the table below will easily discrbe how much one country like India who is growing fastly can concern about the energy supply if it wants to make these trend continue further.

	2004-05 (MMTOE)	2025-26 (MMTOE)		CAGR	
		GDP @7%	GDP@8%	GDP @7%	GDP @8%
COAL	163.81	466	535	5.10%	5.80%
OIL	129.75	273	334	3.60%	4.60%
NATURAL GAS	27.71	113	129	6.90%	7.60%
HYDEL POWER	7.28	28	28	6.70%	6.70%
NUCLEAR POWER	4.38	46	46	11.80%	11.80%
TOTAL	332.93	926	1072	4.99%	5.73%

***Table4.* INDIA'S ENERGY MIX FOR 2004-05 AND 2025-26**

SOURCE: MoPNG, Planning Commission, Government of India.

If we look at the work done and the estimates of energy requirements in this regard, we have a long way to go as far as oil and gas are concerned. We import around 10%of coal while in the oil sector we import around 75% of our requirements and in gas sector we import only 5mt LNG. The domestic crude oil production of the country is 632,000 bbl/d against the demand of 2.5 million bbl/d.further the domestidc productrion is to be flat at 770,000 bbl/d until 2010 while consumption is forecated to hit 3.41million bbl/d implying a 77% import requirement (2.64 million bbl/d) of crude oil to meet the demand. In natural gas front demand in India has various opportunities to the industry players gas demand is rising fast as India develops more gas-fired power station, fertilizer sector is not lagging behind and taken an positive step to sift from naphtha to natural gas for feedstock by 2007.there fore from only 0.63tcf in 1995,natural gas demand is expected to rise to 0.96 tcf by 2010. There is an effective development and exploitation of various sources of energy is prerequisite for economic growth of India. The President of India Dr.A.P.J. Abdul Kalam has stressed that Indian's first & highest priority is to be an energy independence nation by 2030.

Everywhere, one can easily find out Indian efforts to make India a self dependent in concern with energy sector, getting oil & gas equity abroad, changing country's foreign policy not only to make good hormonal relation with the neighboring countries but in each direction around the world USA, UK, LATIN AMERICAN NATIONS, MIDDLE EAST, RUSSIA, FAR EAST, JAPAN, CHINA, KOREA etc, the historic Indo-US deal will not only define India as an emerging super power but also play a vital role for India's future energy supply .the indo-US pact would make a major contribution towards mitigating India's energy deficits.

Our consumption of petroleum products is increasing at the rate of 3.8% per annum during 2002-2004. In 2003-04, net of exports, India consumed 116.01 mt of crude oil products including refinery fuel. At the same time, domestic production of crude oil has been between 30.3 mt to 33.86 mt (See *Figure 8*). Not only the domestic production has stagnated, the oil reserve has hovering between 700 MMT and 750 MMT during this period.

Domestic Consumption & Production of Crude Oil

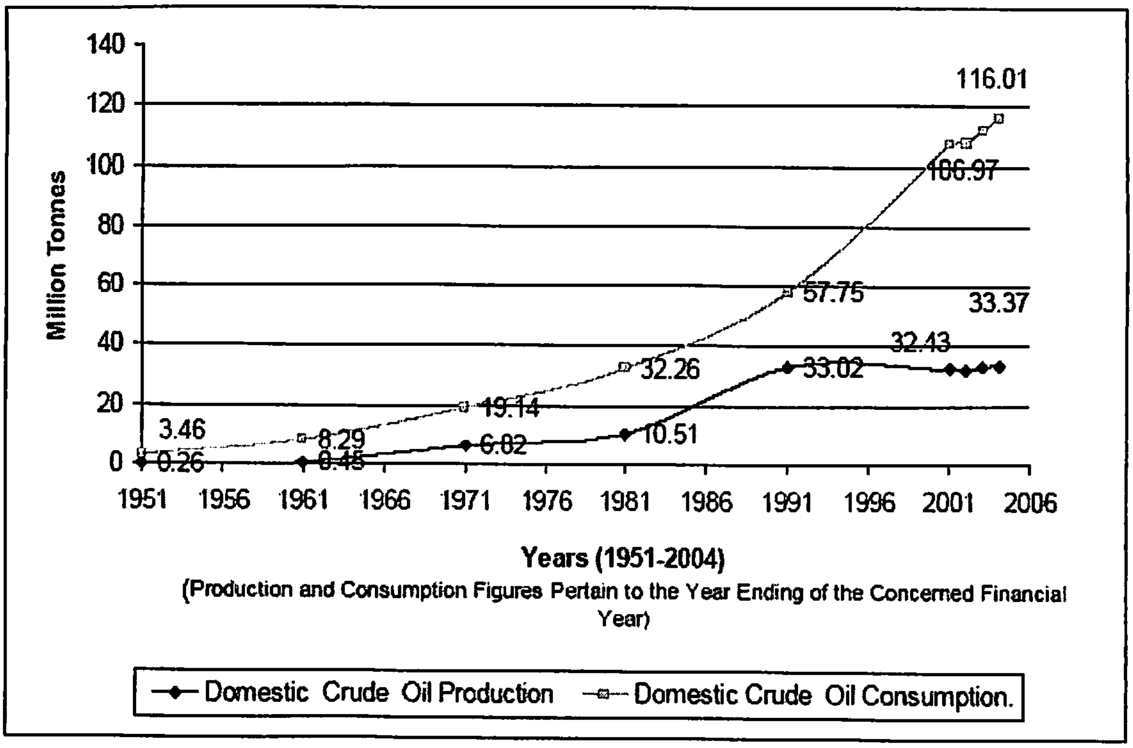


Figure 4 domestic consumption and production of crude oil

Data source: Ministry of Petroleum & Natural Gas

The total reserves were 739 MMT in 1990-91 & were estimated to be 733 MMT in 2003-04. The proved reserves to production (R/P) ratio were 22 in 2003-04. We now import 72.2% of our consumption and our import dependence is growing rapidly. This raises serious concerns about India's energy security, our ability to obtain the oil it needs and the impact on the economy of constrained supply and the consequent increase in oil prices in the world markets. Therefore, the need for an effective and comprehensive energy policy is an urgent imperative.

Coal Shall Remain India's Primary Energy Source till 2031-32, Current shortages are a concern: Coal accounts for over 50% of India's commercial energy consumption and some 78% of domestic coal production is dedicated to power generation. Since prices were de-controlled, the sector has become profitable primarily as a result of price increases and the rising share of open cast production. The present shortage can be addressed by encouraging imports which are also needed from a longer-term perspective. Thus we need to facilitate coal imports and create the needed infrastructure. Imports also put a competitive pressure on domestic coal industry to be efficient. Imported coal is far more cost competitive to imported gas for power generation especially along the western & southern coasts of India. Such a cost advantage is likely to continue.

Natural Gas is a non-tradable commodity in the absences of significant investments in pipelines or, alternatively, in liquification, cryogenic shipping & regasification. Thus the natural gas price can be determined through competition among different producers (this presumes multiple sources and a competitive supply-demand balance) or independently regulated on a cost plus basis including reasonable returns (where competing supply sources are absent and/or demand exceeds available supply). Another option could be to price gas on a net-back-basis. Should a scenario wherein gas becomes 15%-20% of India's energy mix materialise by 2031-32; some 60% to 80% of the gas supply would be used for power generation. This would mean that beyond the level of gas consumption in the fertiliser, petrochemical, automotive and domestic sectors gas must compete with coal, the key alternative for power generation. A competitive coal market is thus important for setting a proper price of natural gas on a net-back-basis. An alternative to pricing domestic gas could be the net realisation of the domestic natural gas producer after investing and getting a return on the infrastructure needed to make the natural gas tradable across borders.

Role of Hydro and Nuclear: It is seen that even if India succeeds in exploiting its full hydro potential of 150,000 MW, the contribution of hydro to the energy mix would be around 5-6%. Similarly, even if a 20-fold increase takes place in India's nuclear power capacity by 2031-32, the contribution of nuclear energy to India's energy mix is also, at best, expected to be 5-6%.

Role of Renewables: From a longer-term perspective and the need to maximally develop domestic supply options as well as the need to diversify energy sources, renewables remain important to India's energy sector. It would not be out of place to mention that solar power could be an important player in India attaining energy independence in the long run. Even with a concerted push of 20-fold increase in capacity, renewables can account for around 5-7% of India's energy mix by 2031-32. While this is small, the distributed nature of renewables can provide many social benefits.

1.4 NATURAL GAS -A BETTER OPTION AND FUTURE.

Energy Efficiency and Demand Side Management:

Lowering energy intensity of GDP growth through higher energy efficiency is key to meeting India's energy challenge & ensuring its energy security. India's energy intensity of growth has been falling and is about half what it used to be in the early seventies. Currently India consumes 0.19 kilogram of oil equivalent per dollar of GDP expressed in purchasing power parity terms. This is equal to the energy intensity of the OECD and better than the 0.21 kilograms of China, 0.22 kilograms of the US and a World average of 0.21. However, there are several countries in Europe at or below 0.12 with Brazil at 0.14 and Japan at 0.15. Thus, clearly there is room to improve and energy intensity can be brought down significantly in India with current commercially available technologies.

Energy and sustainable development are intimately related and the sector occupied an important place at the Earth Summit. Agenda 21 urges countries to enhance the *contribution of environmentally sound and cost-effective energy systems, particularly new and renewable ones, through less polluting and more efficient energy production, transmission, distribution and use.* More specifically, the key issues Highlighted in Agenda 21 and reiterated at the IX session of the Commission on Sustainable Development relate to the following.

- Improving access to energy;
- Addressing environmental and social concerns in the energy sector;
- Enhancing energy efficiency and the use of environmentally sound energy systems (including advanced fossil fuel technologies);

- ▶ Mobilizing financial resources including participation of the private sector;
- ▶ Promoting renewable sources of energy;
- ▶ Addressing issues related to energy use in transportation; and
- ▶ Fostering international and regional co-operation.

Thus, The need for defining an effective and comprehensive energy strategy for India is now an urgent imperative. Not only are there growing uncertainties about the stability and security within the global energy market but the expectations and aspirations of the Indian people for a much higher rate of growth also require a stable, low-cost, and secure supply of energy. The demand for energy is growing to increase significantly in an era where the GDP of India is expected to grow to USD 2 trillion by 2020 from the current level of USD 500 billion. For this reason it becomes essential for India to be energy independent. With 70% oil import and 75% usage of coal for power generation, the economic and ecological distortion caused is huge. Thus there is a need to shift from these energy sources. ***The answer to these is natural gas***. For utilization of this new energy source huge investments are required. *The International Energy Agency (IEA) recently completed a detailed study of energy investment requirements out to 2030. Total estimated investment requirements total US$16 trillion, or one percent of world gross domestic product. Oil accounts for $3.1 trillion, with conventional oil production accounting for the bulk of the investment at $2.2 trillion, and an additional $205 billion needed for nonconventional oil. The investment needs of tankers and pipelines amount to $260 billion, while $410 billion is needed for refineries, predominantly in the Middle East, Africa, and Asia.*

There is also a need for private participation in this sector with the help of the government. The need for the hour is a unified policy. This should aim at an energy strategy, which would serve the objectives of equity, security, efficiency, and environmental protection. To make this strategy we need an actual future scenario that is not at all possible for us until we invent a machine that will travel more than the speed of light. Until that we have to depend on models & forecasting techniques to present a future scenario. It tries to find out the vacuum that needs to be filled to have a sound integrated energy strategy, which is reliable and environmentally responsible. Most of all, our vision of India's future should serve to awaken in all of us a greater awareness of our cultural and spiritual strengths - which formed the bedrock of our past achievements and should form the foundation of our future accomplishments. Some of our traditions must change, but knowledge, in essence, is our greatest endowment. The vision should awaken in us an unswerving confidence in ourselves, a complete reliance on our own capacity as a nation and an unshakeable determination to realize our full potential. A true vision cannot be a static written statement. It must emerge as a living and dynamic reality in the minds and hearts of the people and their leaders. This vision statement of India 2020 may not fulfill all these criteria to our full satisfaction, but it can serve as a useful starting point and foundation for contemplating future possibilities and our destiny as a nation. It can serve to indicate the broad lines of policy and strategy by which India can emerge as a far stronger, more prosperous and more equitable nation in the coming years. This document draws upon many ideas and proposals contained in more than thirty background papers presented to the Committee over the last two years, which have been presented in the main body.

Chapter 2

Natural Gas- world outlook.

Introduction

Natural gas is the fastest growing primary energy source in the IEO2005 forecast. Consumption of natural gas is projected to increase by nearly 70 percent between 2002 and 2025, with the most robust growth in demand expected among the emerging economies.

Natural gas is projected to be the fastest growing component of world primary energy consumption in the *International Energy Outlook 2005* (*IEO2005*) reference case. Consumption of natural gas worldwide increases in the forecast by an average of 2.3 percent annually from 2002 to 2025, compared with projected annual growth rates of 1.9 percent for oil consumption and 2.0 percent for coal consumption. From 2002 to 2025, consumption of natural gas is projected to increase by almost 70 percent, from 92 trillion cubic feet to 156 trillion cubic feet (Figure 5), and its share of total energy consumption on a Btu basis is projected to grow from 23 percent to 25 percent. The electric power sector accounts for almost one-half of the total incremental growth in worldwide natural gas demand over the forecast period.

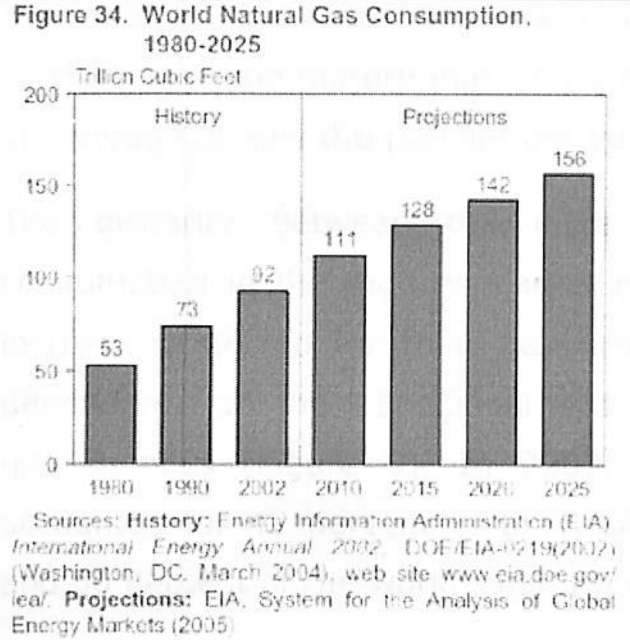


Figure 5.World Natural Gas Consumption, Source EIA.

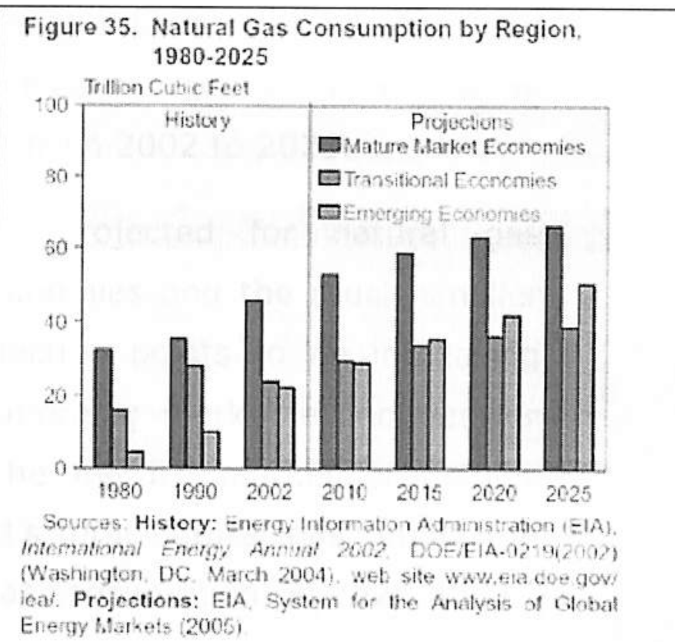


Figure 6 Natural Gas Consumption by Region 1980-2025, Source: EIA

On a regional basis, the largest increases in natural gas consumption worldwide are projected for the transitional economies of Eastern Europe and the former Soviet Union (EE/FSU) and for emerging Asia (Figures 6 and 7). Natural gas use in the EE/FSU expands by 63 percent over the projection period; and in emerging Asia, gas use is expected to nearly triple from 2002 to 2025. In the mature market economies, where natural gas markets are more established, consumption of natural gas is projected to increase by a more modest annual average of 1.6 percent from 2002 to 2025, with the largest incremental growth in the mature market economies projected for North America, at 11 trillion cubic feet.

The emerging economies are also expected to show the strongest growth in natural gas production, with a projected average increase of 4.1 percent per year from 2002 to 2025 in the reference case (Figure 8). In contrast, natural gas production in the transitional economies is projected to grow at an average annual rate of 2.3 percent, and production in the mature market economies is expected to increase by an average of only 0.6 percent per year from 2002 to 2025.

The disparity between the increase projected for natural gas consumption in the mature market economies and the much smaller increase projected for their gas production points to an increasing dependence on the transitional and emerging market economies for gas supplies (Figure 9). In 2002, the mature market economies accounted for 42 percent of the world's total natural gas production and 50 percent of the world's natural gas consumption; in 2025, they

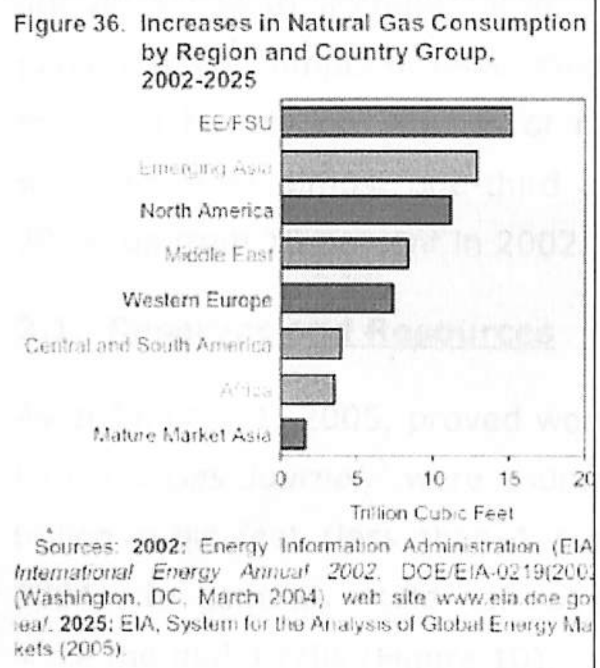


Figure 7. increase in Natural Gas Consumption by Region and Country Group, Source: EIA.

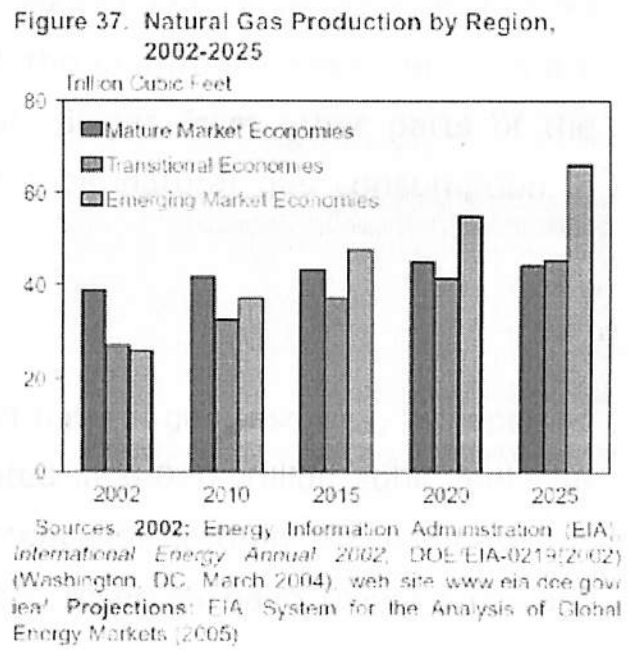


Figure 8. Natural gas Production by Region, 2002-2025,Source: EIA.

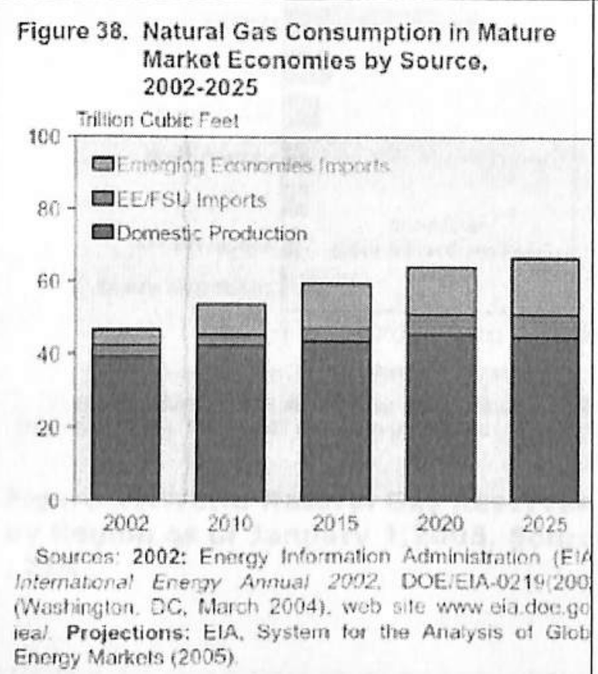


Figure 9. Natural Gas Consumption in mature market Economies by Source 2002-2025, Source: EIA.

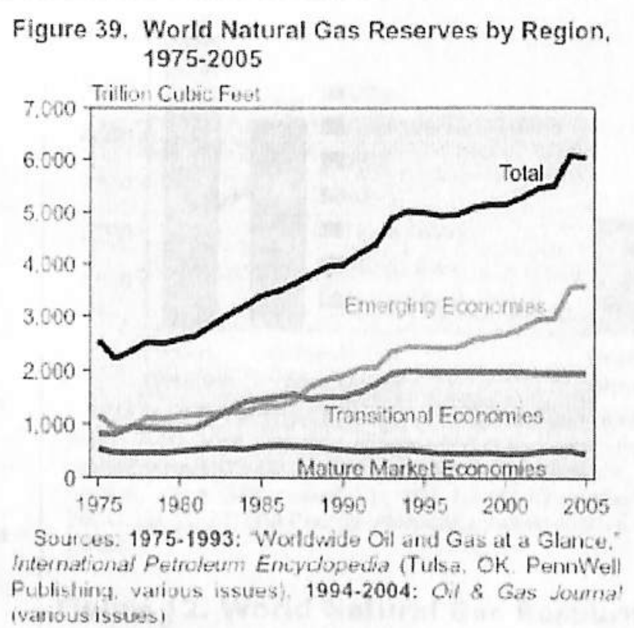


Figure 10. World Natural Gas Rserves by Region,1975-2005, Source: EIA.

are projected to account for only 29 percent of production and 43 percent of consumption. As a result, the mature market economies are expected to rely on imports of natural gas from other parts of the world to meet almost one-third of their natural gas consumption in 2025, up from 15 percent in 2002.

2.1. <u>Reserves and Resources</u>

As of January 1, 2005, proved world natural gas reserves, as reported by *Oil & Gas Journal*,[3] were estimated at 6,040 trillion cubic feet—36 trillion cubic feet (less than 1 percent) lower than the estimate for 2004 . In general, world natural gas reserves have trended upward since the mid-1970s (Figure 10).

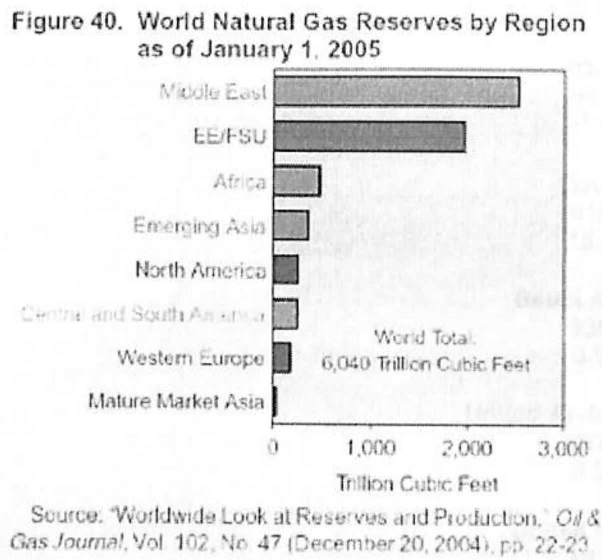


Figure 11.World Natural Gas Reserves by Region as of January 1,2005, Source : EIA

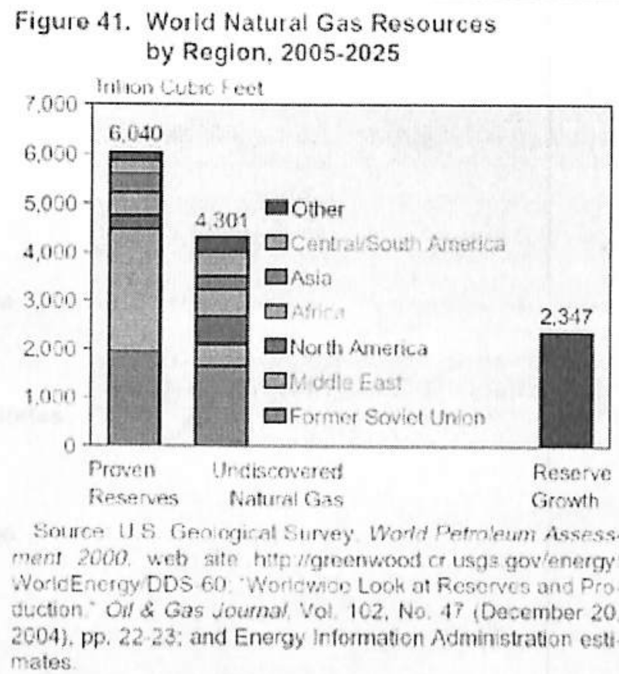


Figure 12. World Natural Gas Resources by Region, 2005-2025, Source: EIA

The largest revision to natural gas reserve estimates was made in Australia. The Australian government reported a two-thirds cut in its estimate of natural gas reserves between 2004 and 2005, from 90 trillion cubic feet to 29 trillion cubic feet. Higher reserve estimates were recorded for the emerging economies,

Table 5. World Natural Gas Reserves by Country as of January 1, 2005

Country	Reserves (Trillion Cubic Feet)	Percent of World Total
World	6,040	100.0
Top 20 Countries	5,391	89.3
Russia	1,680	27.8
Iran	940	15.6
Qatar	910	15.1
Saudi Arabia	235	3.9
United Arab Emirates	212	3.5
United States	189	3.1
Nigeria	176	2.9
Algeria	161	2.7
Venezuela	151	2.5
Iraq		

	110	1.8
Indonesia	90	1.5
Malaysia	29	0.5
Norway	75	1.2
Turkmenistan	74	1.2
Uzbekistan	71	1.2
Kazakhstan	66	1.1
Netherlands	65	1.1
Canada	62	1.0
Egypt	57	0.9
Ukraine	40	0.7
Rest of World	**649**	**10.7**

mostly in Africa and the Middle East. Nigeria alone accounted for most of the increment in Africa, with a gain of 17 trillion cubic feet (11 percent), and Libya reported a smaller increase of 6 trillion cubic feet (12 percent). In the Middle East, Saudi Arabia increased its estimate of reserves by 4 trillion cubic feet (2 percent), accounting for all of the region's addition to reserves. Elsewhere, national estimates of natural gas reserves changed little over the 1-year period.

Almost three-quarters of the world's natural gas reserves are located in the Middle East and in the transitional economies of the EE/FSU (Figure 11). Russia, Iran, and Qatar combined account for about 58 percent of the world's natural gas reserves (Table 5). Reserves in the rest of the world are fairly evenly distributed on a regional basis.
Despite high rates of increase in natural gas consumption, particularly over the past decade, most regional reserves-to-production ratios have remained high. Worldwide, the reserves-to-production ratio is estimated at 66.7 years . Central and South America has a reserves-to-production ratio of 55.0 years, the FSU 77.4 years, and Africa 96.9 years. The Middle East's reserves-to-production ratio exceeds 100 years.

The U.S. Geological Survey (USGS) periodically assesses the long-term production potential of worldwide petroleum resources (oil, natural gas, and natural gas liquids). According to the most recent USGS estimates, released in the *World Petroleum Assessment 2000*, a significant volume of natural gas remains to be discovered. The mean estimate for worldwide-undiscovered natural gas is 4,301 trillion cubic feet (Figure 12), which is approximately double the worldwide cumulative consumption forecast from 2002 to 2025 in *IEO2005*. Of the total natural gas resource base, an estimated 3,000 trillion cubic feet is in "stranded" reserves, usually located too far away from pipeline infrastructure or population centers to make transportation of the natural gas economical. Of the new natural gas resources expected to be added over the next 25 years, reserve growth accounts for 2,347 trillion cubic feet. More than one-half of the mean undiscovered natural gas estimate is expected to come from the FSU, the Middle East, and North Africa; and about one-fourth (1,065 trillion cubic feet) is expected to come from a combination of North, Central, and South America.

2.2 Regional Forecasts

2.2.1 North America

North America's natural gas production[4] is expected to grow at an average annual rate of 0.5 percent between 2002 and 2025 in the *IEO2005* forecast, whereas its gas consumption (Figure 13) is expected to grow by 1.5 percent per year. In 2002, most of the natural gas consumed in North America was produced within the region (Figure 14). In 2015, however, North America is projected to consume 5.7 trillion cubic feet more than it produces, and in 2025 the gap between North America's natural gas production and consumption is projected to be 8.0 trillion cubic feet, illustrating the region's growing dependence on imports.

Currently, Canada supplies the bulk of U.S. imports of natural gas, the United States supplies most of Mexico's import needs, and less than 1 percent of North America's natural gas demand in 2002 was met by imports from outside the region (Figure 14). Imports from other regions are all in the form of liquefied natural gas (LNG) into the United States through one of five existing LNG regasification facilities. Four are onshore terminals that were built more than 20 years ago, located in Everett, Massachusetts, Cove Point, Maryland, Elba Island, Georgia, and Lake Charles, Louisiana. The fifth is the Gulf Gateway Energy Bridge, located in the offshore Gulf of Mexico. It is the first new U.S. LNG terminal to be constructed in more than 20 years, and it received its first cargo on March 17, 2005.

LNG imports are expected to increase substantially and play a prominent role in the future, with LNG imports into the United States surpassing pipeline imports from Canada by 2015. Although Mexico is expected to remain a net importer from the United States, LNG imports are expected to begin reducing Mexico's dependence on the United States in 2007.

New LNG regasification facilities are expected to begin operating in Mexico, the United States, and Canada between 2005 and 2010. After 2010, the region's import capacity continues to expand throughout the remainder of the forecast period. More than 50 proposals to build new regasification facilities in North America have been put forth, and projects in all three countries have already received at least some of the needed regulatory approvals. If all the proposed facilities were constructed, they would add more than 20 trillion cubic feet to the region's import capacity, equivalent to almost 75 percent of the natural gas consumed in North America in 2002; however, the *IEO2005* reference case does not assume that all the proposed facilities will be built. Still, the level of activity is a clear indication that LNG is poised to play a much greater role in North American gas markets in the future.

According to EIA's *Annual Energy Outlook 2005* (*AEO2005*), the share of total U.S. natural gas consumption met by net imports of LNG is expected to grow from about 1 percent in 2002 to 15 percent (4.3 trillion cubic feet) in 2015 and 21 percent (6.4 trillion cubic feet) in 2025. LNG terminals are expected to be built relatively early in the forecast, with new terminals receiving supplies on the Gulf Coast and in the Bahamas by 2010. A new terminal in Baja California, Mexico, is projected to begin operation in 2007 to serve Northern Mexico and Southern California, with additional capacity in Baja California added after 2020. Although new U.S. terminals are projected to be constructed along the East Coast after 2015, the Gulf Coast is expected to be the primary location for new LNG import capacity.

Most of the projected new U.S. LNG capacity is located in the Gulf of Mexico because of the locale's many advantages. There is spare capacity in the existing pipeline infrastructure to move natural gas to market, and deepwater ports are available to serve onshore facilities. In addition, offshore pipeline systems are in place to move natural gas to shore from offshore facilities. The extensive pipeline grid provides a ready ability to blend gases of varying heat content and thus, handle high-Btu LNG. Finally, the local environment appears to be favorable for the permitting of new facilities. Imports into new Gulf Coast terminals are expected to account for more than 70 percent of imports into new U.S. LNG terminals in 2025.

Canada is the only North American country that currently produces more natural gas than it consumes, and its domestic production is projected to continue to exceed its consumption through 2025. Most of Canada's natural gas production currently comes from the Western Sedimentary Basin. Although conventional production in the basin is in steady decline, the decreases are expected to be more than offset by increases in unconventional production in western Canada, conventional production in the MacKenzie Delta and Eastern Canada, and LNG imports. Supply is also expected to be supplemented by natural gas from the MacKenzie Delta. A pipeline to bring natural gas from the MacKenzie Delta to market is expected to open in 2010. In spite of these supply additions, pipeline imports from Canada are expected to decline toward the end of the forecast because of strong growth in Canada's internal need for natural gas.

In the *IEO2005* reference case, Canada's natural gas production is projected to grow at an average annual rate of 0.1 percent. Whereas in 2002, production exceeded consumption in Canada by 3.6 trillion cubic feet, excess production available for export to the United States is expected to drop to 2.5 trillion cubic feet in 2015 and to 2.1 trillion cubic feet in 2025.

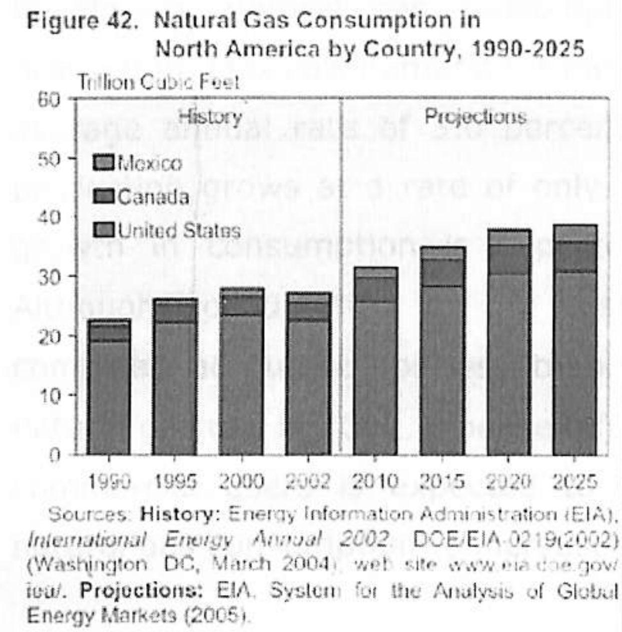


Figure 13. Natural Gas Consumption in North America by Country, 1990-2025, Source: EIA

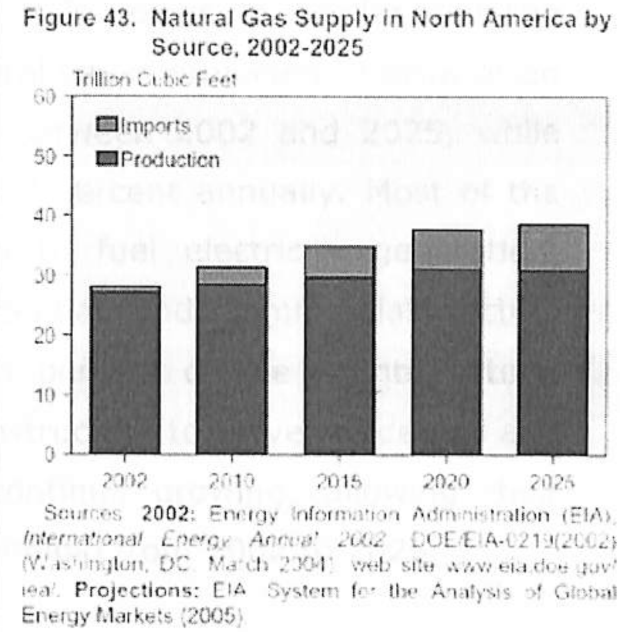


Figure 14. Natural Gas Supply in North America, 2002-2025, Source: EIA

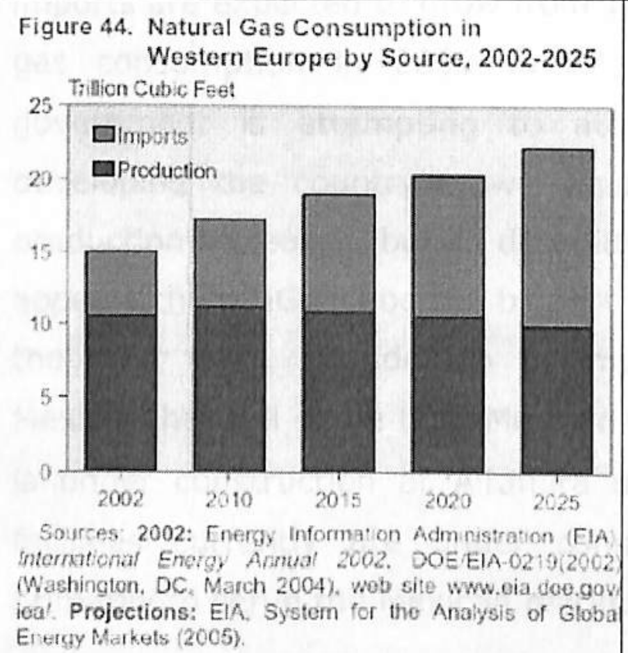


Figure 15. Natural Gas Consumption in Western Europe by Sources, Source: EIA

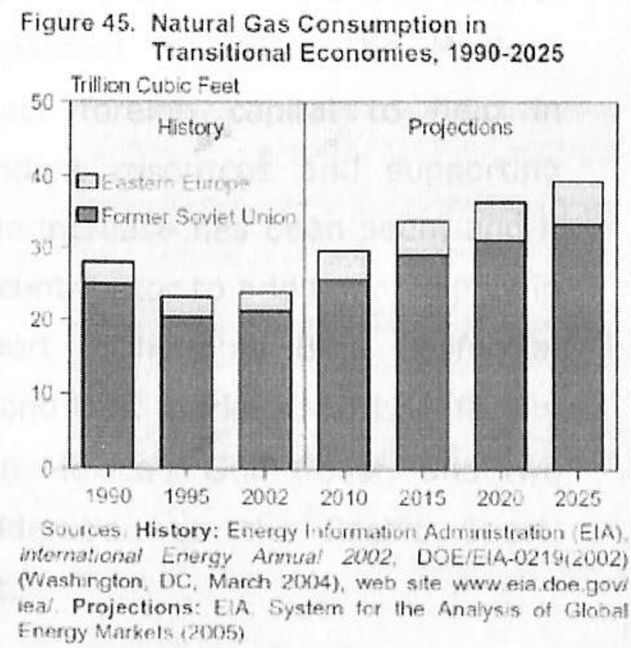


Figure 16.Natural Gas Consumption in Transitional Economies, 1990-2025, Source: EIA.

In Mexico, natural gas consumption is expected to far outstrip production. Mexico's demand for natural gas is projected to grow at an average annual rate of 3.0 percent between 2002 and 2025, while production grows at a rate of only 1.7 percent annually. Most of the growth in consumption is expected to fuel electricity generation. Although consumption in the residential and commercial sectors combined accounted for less than 3 percent of the country's total natural gas use in 2002, pipeline infrastructure to serve residential and commercial users is expected to continue growing, allowing their natural gas consumption to increase tenfold from 2002 to 2025.

Mexico's dependence on natural gas imports, like that of the United States, is projected to increase. In the *IEO2005* reference case, imports are expected to grow from 13 percent of Mexico's total natural gas consumption in 2002 to 37 percent in 2025. The Mexican government is attempting to attract foreign capital to help in developing the country's own abundant resources and supporting production increases, but to date little increase has been seen, and it appears that LNG will be the biggest contributor to additional supply in the near term. In addition to import facilities in Baja California, Mexico, that will serve both Mexican and U.S. markets, an LNG facility is under construction at Altamira on Mexico's Gulf Coast, and two facilities currently are under consideration on the Pacific Coast, primarily to serve the Mexican market.

2.2.2 Western Europe

Natural gas is expected to be the fastest growing fuel source in Western Europe, with demand projected to grow at an annual average rate of 1.8 percent, from 15.0 trillion cubic feet in 2002 to 22.4 trillion cubic feet in 2025. More than 60 percent of incremental gas consumption in Western Europe between 2002 and 2025 is expected to be used for electric power generation. Natural gas is the fuel of choice for new electricity generation capacity in Western Europe, where many nations are looking to replace oil- and coal-fired plants that are more carbon intensive than natural gas. In addition, natural gas is expected to remain more cost competitive than renewable energy sources, and countries such as Germany and Belgium have government policies that discourage the expansion of nuclear power capacity and may result in the retirement of existing nuclear power plants over the forecast period.

Natural gas consumption for electricity generation in Western Europe is projected to increase on average by 3.6 percent per year from 2002 to 2025, surpassing the use of coal and renewables for electricity generation (on a Btu basis) by 2015 and the use of nuclear power by 2025. The share of total electricity sector energy demand met by natural gas is projected to increase from 14 percent in 2002 to 23 percent in 2015 and 28 percent in 2025.

With the notable exception of Norway, natural gas production is in decline in most areas of Western Europe. In the mid-term future, production from Norway is expected to stave off a decline in the region's overall production; however, total natural gas production in Western Europe is still far from keeping pace with demand (Figure 15). Western Europe received net imports of 4.9 trillion cubic feet of natural gas in 2002, accounting for one-third of total gas consumption. The region's reliance on imported gas is projected to grow to more than 40 percent of demand in 2015 and more than 50 percent in 2025. Currently there are 10 LNG regasification terminals operating in Western Europe, and LNG receiving capacity is being expanded aggressively. More than 20 new facilities have been proposed, including 4 that are under construction. Egypt, a new addition to the list of LNG suppliers to the world as well as to Europe, sent its first-ever LNG cargo to Spain in March 2005

2.2.3 Mature Market Asia

In Japan, natural gas shows the largest incremental growth in demand among primary energy sources over the forecast period. Japan's natural gas consumption is projected to increase at an average annual rate of 1.5 percent, from 2.7 trillion cubic feet in 2002 to 3.8 trillion cubic feet in 2025. Natural gas use in the industrial sector is projected to grow by 3.4 percent per year on average from 2002 to 2025, and to claim an increasing share of the country's total gas consumption. Electricity generation remains by far the largest use for natural gas in Japan, however, despite an expected decline in its share of the total, from 71 percent in 2002 to 67 percent in 2025.

In Australia and New Zealand, the industrial sector currently is the predominant user of natural gas, and it is projected to account for more than one-half of all gas consumption in Australia and New Zealand throughout the forecast period. Natural gas is also the fastest growing fuel in the region's electricity sector. Natural gas consumption as a percentage of total energy use in the electric power sector is projected to grow from 11 percent in 2002 to nearly 13 percent in 2025, but this will have only a modest impact on the electric power sector fuel mix, which is dominated by coal. Even in 2025, coal is expected to account for almost 73 percent of energy consumption in Australia and New Zealand's electric power sector on a Btu basis.

2.2.4 Transitional Economies

In the EE/FSU countries, natural gas consumption in the electric power sector is expected to surpass consumption in the industrial sector by 2010, and to account for 44 percent and 43 percent of total gas consumption in 2025 in the FSU and Eastern Europe, respectively. Total natural gas demand in the EE/FSU region is projected to grow at an average annual rate of 2.2 percent from 2002 to 2025 (Figure 16). In both Eastern Europe and the FSU, the electric power sector is expected to account for nearly 60 percent of the total increment in natural gas use over the forecast period.

The FSU, which holds around 30 percent of the world's natural gas reserves, is much more dependent on natural gas for its energy supply than is Eastern Europe (51 percent of total energy consumption in the FSU was supplied by natural gas in 2002, compared with 23 percent in Eastern Europe). Natural gas production in the FSU is projected to grow at an average annual rate of just over 2 percent from 2002 to 2025, and exports are projected to increase to around one-quarter of total gas production in 2025 from 19 percent in 2002. Despite the Russian government's recent dismantling of the oil giant Yukos, foreign companies—especially Western European companies—have increasingly been pursuing investments in Russia's upstream gas sector. Gazprom, the majority state-owned Russian gas company, currently has a spate of suitors from which to choose its partners in the development of the giant Shtokmanovskoye field .

2.2.5 Emerging Asia

In China, natural gas is currently a minor fuel in the overall energy mix, representing only 3 percent of total primary energy consumption in 2002; however, China is rapidly expanding infrastructure to facilitate the consumption of gas throughout the country as well as imports of gas into the country. Overall natural gas consumption in China is projected to grow at an average annual rate of 7.8 percent, from 1.2 trillion cubic feet in 2002 to 6.5 trillion cubic feet in 2025 (Figure 17.46). Only nuclear power generation is projected to grow more rapidly, at a 9.9-percent average annual rate over the forecast period.

Natural gas consumption in China's residential sector, projected to more than double from 2002 to 2010, received a boost with the start of commercial operation of the West-East pipeline in December 2004. Most of the early natural gas coming off the pipeline has been going to residential consumers and the remainder to industrial consumers . The pipeline is far from full utilization, because several natural-gas-fired electric power plants, which ultimately are to be the main consumers of West-East gas, are not yet complete and operational.

In the long term, the electric power sector is the main source of projected growth in China's natural gas demand, accounting for fully two-thirds of the total increment in China's natural gas consumption from 2002 to 2025. In 2002, natural gas consumption in the electric power sector was 0.2 trillion cubic feet, accounting for only 1 percent of the country's total electricity generation. In 2010, natural gas consumption in the electricity sector is projected to surpass consumption in the industrial and residential sectors, and in 2025 it is projected to surpass their combined consumption, accounting for more than one-half of China's total natural gas use.

In India, as in China, natural gas is currently a minor fuel in the overall energy mix, representing only 6.5 percent of total primary energy consumption. Also like China, India is rapidly expanding infrastructure to facilitate consumption and imports of gas. Overall, India's gas consumption is projected to grow at an average annual rate of 5.1 percent, from 0.9 trillion cubic feet in 2002 to 2.8 trillion cubic feet in 2025. The electric power sector is projected to account for 71 percent of the total incremental growth in India's natural gas demand from 2002 to 2025.

Total natural gas consumption in South Korea is projected to grow at an average annual rate of 3.7 percent from 2002 to 2025. In 2002, the residential sector was the country's predominant consumer of natural gas, accounting for 37 percent of the total, and the electric power sector was a close second, accounting for 34 percent of total gas use. In the forecast, natural gas use in South Korea's industrial sector increases on average by 7.0 percent per year from 2002 to 2025, compared with average annual growth of 1.7 percent in both the residential and electric power sectors. In 2015, more natural gas consumption is expected in the country's industrial sector than in its residential or electric power sector. In 2025, industrial natural gas use is projected to account for more than 40 percent of all the natural gas consumed in South Korea.

High world oil prices, beginning in 1999, provided the impetus for the strong growth in gas use in South Korea's industrial sector, and it is partially at the expense of oil consumption that natural gas is expected to grow in this sector. On a Btu basis, the share of total industrial consumption attributable to natural gas is projected to grow from just 5 percent in 2002 to almost 16 percent in 2025, and the share attributable to oil is expected to shrink from 58 percent in 2002 to just under 50 percent in 2025.

In the other countries of emerging Asia, total natural gas consumption is projected to grow at an average annual rate of 2.9 percent from 2002 to 2025. Natural gas consumption in 2002 and throughout the forecast period is fairly evenly split between the industrial and electricity sectors, with each accounting for more than 40 percent of total gas consumption. Penetration of gas into the residential, commercial, and transportation sectors is projected to remain low with the three sectors combined continuing to account for less than 10 percent of total gas consumption in the other countries of emerging Asia throughout the forecast period. Natural gas infrastructure across the region is fragmented, with limited infrastructure outside producing areas, and extensive advances will be needed to meet growing demand in the long term.

2.2.6 Middle East

Natural gas consumption in the Middle East is projected to double between 2002 and 2025 (Figure 18). The overall share of natural gas in the Middle East's fuel consumption mix increases over the forecast period at the expense of oil, although oil will remain the region's predominant fuel source. The share of total Middle East energy demand met by natural gas is projected to increase from 39 percent in

2002 to 45 percent in 2025, while the share of total energy demand met by oil is projected to decline from 53 percent to 48 percent.

Natural gas is projected to retain its dominant position in the Middle East's power sector, with 1.9-percent average annual growth over the forecast period. In the industrial sector, however, natural gas use is projected to grow by 4.0 percent per year, accounting for more than two-thirds of the overall incremental growth in gas demand in the region from 2002 to 2025. The natural gas share of total energy consumed in the region's industrial sector is projected to grow from 46 percent in 2002 to 59 percent in 2025, and oil is expected to lose share in the sector (from 41 percent of industrial energy consumption in 2002 to just under 30 percent in 2025).

Oil-exporting countries in the region have deliberately sought to expand domestic gas use in order to make more oil available for export. Many gas-rich countries in the region are also developing projects to monetize their natural gas resources, in particular through LNG and, more recently, gas to liquids (GTL) projects (see discussion on "Gas to Liquids: A New Frontier for Natural Gas"). Qatar has secured several high-profile deals that, when realized, will eventually boost its total LNG exports to 77 million metric tons per year. One such deal is for the construction of what will be the two largest liquefaction trains in the world, at 7.8 million metric tons per year each.

2.2.7 Africa

Natural gas consumption in Africa is projected to grow at an average annual rate of 4.0 percent from 2002 to 2025 (Figure 19), compared with average yearly growth rates of 2.7 percent for oil and 1.6 percent for coal. Gas consumption is expected to surpass coal consumption by 2025, with oil remaining the dominant fuel throughout the projection period. Incremental growth in Africa's gas demand from 2002 to 2025 is projected to be fairly even across sectors, with the industrial, residential, and electric sectors each accounting for around one-third of total growth. Significant flaring of associated gas is still common in Africa because of the remoteness of much of the production and a lack of infrastructure to use all the associated gas produced. Despite continuing instability in some countries of the region, the investment climate in Africa appears to be welcoming to foreigners, with massive investments planned for Egypt, Libya, Algeria, Nigeria, and other parts of West Africa.

2.2.8 Central and South America

Natural gas is expected to be the fastest growing fuel source in Central and South America, with demand projected to increase on average by 3.3 percent per year, from 3.6 trillion cubic feet in 2002 to 7.5 trillion cubic feet in 2025 (Figure 20). By 2010, natural gas is expected to overtake oil as the second most prevalent fuel for electricity generation in the region, with renewables—particularly, hydropower—retaining their dominant share in the sector throughout the forecast period.

The investment climate for natural gas production projects in Central and South America has been less than ideal. Although Venezuela appears to be more welcoming to foreign investment in its natural gas sector than its oil sector, negotiations, especially on the Mariscal Sucre project, continue with no final decisions taken . In Bolivia, two successive presidents were forced to resign by street protests over the handling of the nation's natural gas resources. (Gonzalo Sanchez de Lozado resigned in October 2003, and Carlos Mesa resigned in June 2005.) Protestors have called for increased government involvement in the natural gas sector, including possible nationalization of the industry. On the other hand, Brazil is proceeding with natural gas exploration and hopes to become self-reliant in the gas sector in the future. Major investments in the natural gas sector are underway in Trinidad and Tobago and in Peru.

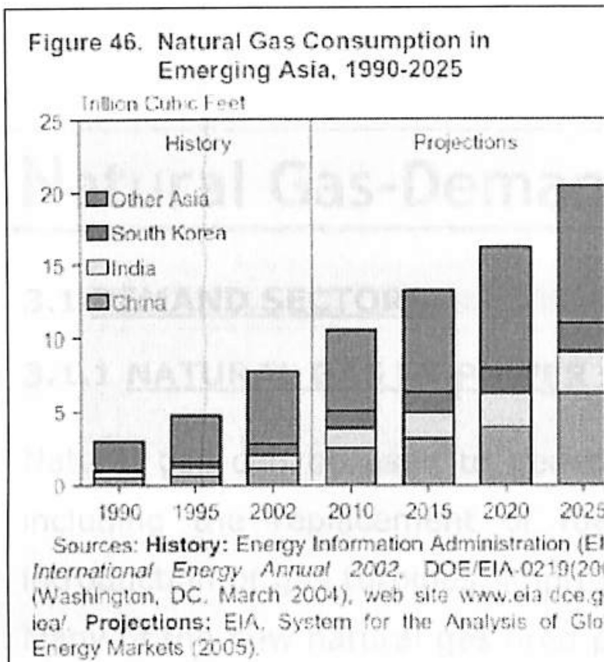


Figure 17. Natural Gas Consumption in Emerging Asia, 1990-2025, Sources: EIA

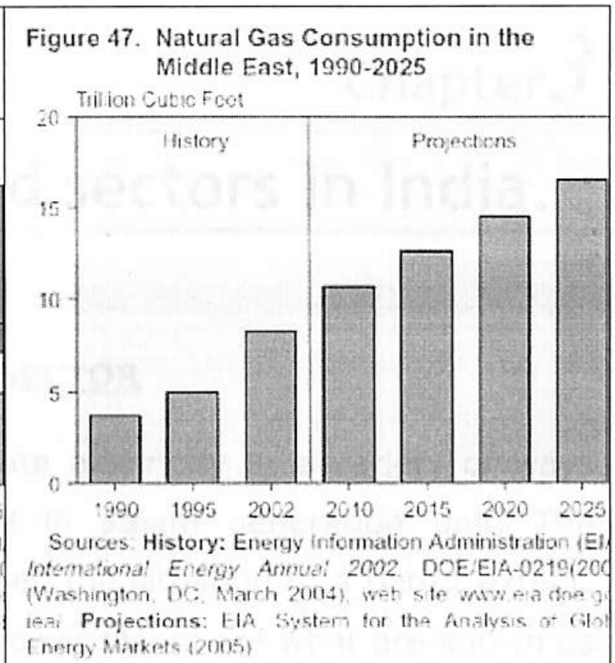


Figure 18. Natural Gas Consumption in Middle East, 1990-2025, Source: EIA

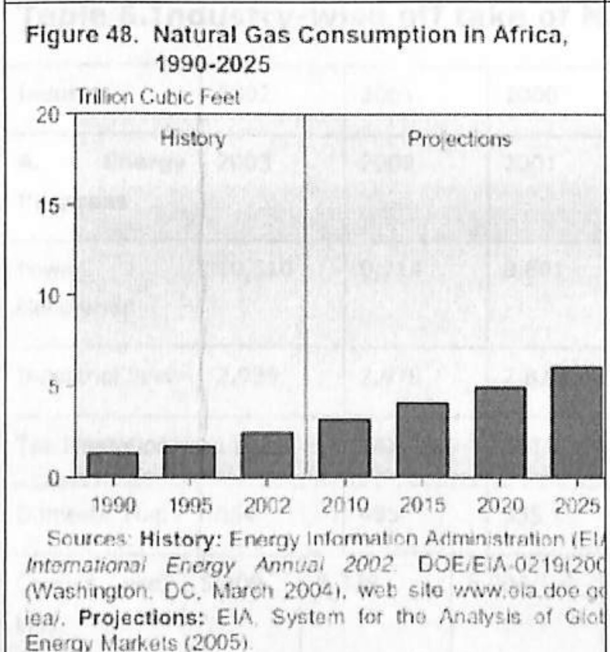


Figure 19.Natural Gas Consumption in Africa, 1990-2025, Source: EIA.

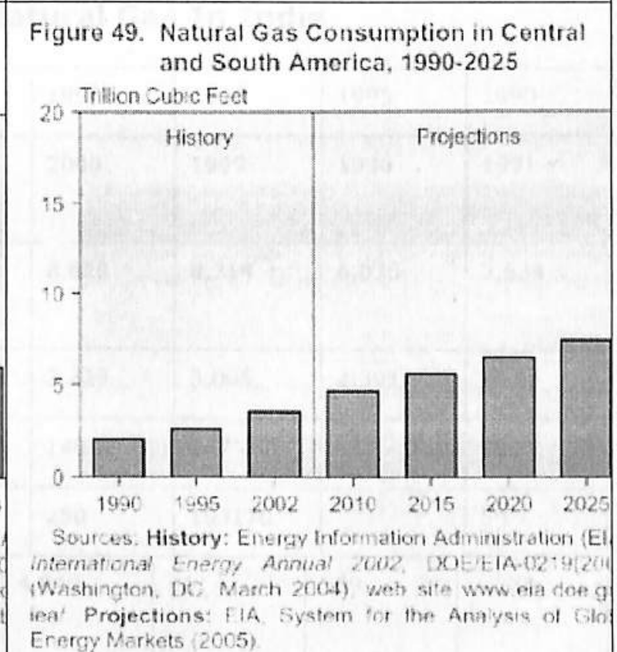


Figure 20. Natural Gas Consumption in Central and South America, 1990-2025,Sources: EIA

Chapter 3

Natural Gas-Demand sectors in India.

3.1 DEMAND SECTORS.

3.1.1 NATURAL GAS IN POWER SECTOR

Natural gas can be used to generate electricity in a variety of ways including the replacement of fuel in steam generation unit. The introduction of gas turbines, improved the situation to a better extent. Many of the new natural gas fired power plants are what are known as combined-cycle' units. In these types of generating facilities, there is both a gas turbine and a steam unit, all in one. In combined-cycle

Table 6.Industry-wise off take of Natural Gas In India

Industry	2002	2001	2000	1999	1998	1995	1990
A. Energy Purposes	2003	2002	2001	2000	1999	1996	1991
Power Generation	10,510	9,214	8,801	8,829	8,714	6,836	3,634
Industrial Fuel	2,939	2,979	2,870	2,329	3,005	2,301	827
Tea Plantation	119	147	151	140	147	111	89
Domestic Fuel	654	485	335	250	193178		50
Captive use/ LPG Shrinkage	5,409	5,339	5,004	4,840	911	589	1,775
Others	136	70	38	36	0	0	0
Total	19,767	18,234	17,199	16,424	12,970	10,015	
B. Non-Energy							

Purposes							
1. Fertilizer Industry	7,955	7,957	8,480	8,592	8,869	7,602	5,612
2. Petrochemical	1,027	909	779	666	650	474	409
3. Others	1,223	937	1,402	1,203	0	0	370
Total	10,205	9,803	10,661	10,461	9,519	8,076	6,391
Grand Total	29,972	28,037	27,860	26,885	22,489	18,091	12,766
(A+B)							
Percentage of Grand Total							
Energy Purposes	66.0	65.0	61.7	61.1	57.7	55.4	49.9
Non-Energy Purposes	34.0	35.0	38.3	38.9	42.3	44.6	50.1

Source : MO&NG, Govt. of India.

plants, the waste heat from the gas-turbine process is directed towards generating steam, which is then used to generate electricity much like a steam unit. Because of this efficient use of the heat energy released from the natural gas, combined-cycle plants are much more efficient that steam units or gas turbines alone. In fact, combined plats can achieve thermal efficiencies of up to 50 60 percent. Now there is a trend towards 'distributed generation units at residential, commercial, and industrial sites of use. This refers to the practice of generating electricity on-site, instead of in a large centralized power plant. Distributed generation offers opportunities across all sectors, from very small residential and commercial on-site generators, to larger output industrial generators.

Table.7 Power plants that runs in gas (of NTPC), Source: National Thermal Power Corporation.

Plant	Fuel Used	Capacity (MW)
Dadri, UP	Gas/Liquid fuel	817
Jhanor-Gandhar, Gujarat	Gas/Liquid fuel	684
Kayamkulam, Kerala	Gas/Liquid fuel	400
Faridabad, Haryana	Gas/Liquid fuel	400
Anta, Rajasthan	Gas/Liquid fuel	413
Auraiya, UP	Gas/Liquid fuel	652
Kawas, Gujarat	Gas/Liquid fuel	645

Source: National Thermal Power Corporation. A Government Enterprise. **Table .8 shows two scenarios in which gas is imported at two different import prices and its effect on the demand and the CAGR. For the low price scenario a CAGR of 12.5% is expected and for a high price scenario a CAGR of 10.8% is expected. Source: www.eia. doe.gov.html .**

Scenario	2002	2007	2012	2028
Imported value $ 4/MMBTU				
Gas based capacity (MW)	10,307	17,190	23,208	42,309
Gas demand (MMSCMD)	40	67	90	143
Imported value $ 3MMBTU				
Gas based capacity (MW)	17,192	30,161	43,440	57,420
Gas demand (MMSCMD)	67	119	168	208

3.1.2 NATURAL GAS IN FERTILIZER SECTOR

The fertilizer industry particularly nitrogenous fertilizers, is highly energy intensive. It is one of the largest consumers of petroleum based fuels and feed stock. The fertilizer sector is one of the two biggest customer segments for natural gas along with power sector. In 2002-03, the off take by fertilizer sector was 26.5 per cent while for power sector it was 35.1 per cent. The production of fertilizer in India in 2002-03 was 14.7 MMPTA while the total consumption 03 was about 18MMTPA (in terms of nutrients). The import accounted for the rest. The consumption has grown at a CAGR of 1.76 per cent in past four years. Natural Gas is used in manufacturing of nitrogen based fertilizer which accounted for around two-thirds of the total consumption though it share in the total fertilizer consumption though its share in the total fertilizer consumption is slightly decreasing whiles the share of phosphates (at 25.2 per cent) and potassic (at 9.6 per cent) based fertilizer is increasing. The total nitrogenous capacity of the fertilizer plants is about II MTPA (excluding plants with capacity *of* about 1.1 MTP 1\ that use external ammonia). About 43 per cent of this capacity is only natural gas based, 18 percent capacity is based on dual fuel of gas and naphta.8 percent only on fuel oil including LSHS and 3 percent only on fuel oil including LSHS and 3 per cent plants are based on plants that use naphtha and fuel oil. Natural gas is the preferred feedstock because of the lower capital costs and operating costs *of* the gas based fertilizer plants. Further they have high-energy efficiency, are relatively environment friendly, und give better capacity utilization. Producing one metric tone of ammonia with natural gas requires just 26Gcal of energy while naphtha based and fuel oil bused plants require 11.3 Gcal und 14.3 Gcal respectively. Currently private sector account for 48.3% of nitrogenous fertilizer production, as compared to 26.7%

percent and 25.0% correspondingly for public and co-operative enterprises.

In terms of calorific content, natural gas is the largest source of energy for the fertilizer industry. The sale of natural gas to fertilizer industry increased from 20.79 MMSCMD in 1995-96 to 22.10 MMSCMD in 2001-02 and reached 22, 49 MMSCMD during April-September 2002. The share of natural gas as feedstock in nitrogenous fertilizer production is 48 per cent followed by naphtha, which has 26 per cent Fuel oil and mix feed have a share of 12 percent and 14 percent respectively. The following graph clearly depicts the usage of different feedstocks for fertilizer industry.

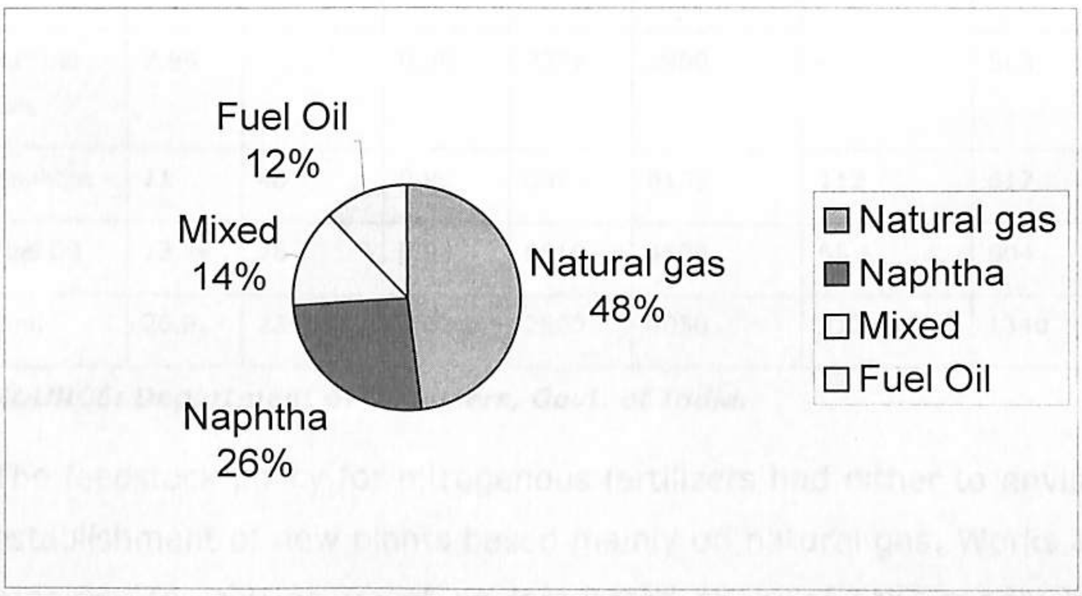


Figure 21. Natural Gas Consumption, in different sectors, in India. Total consumption 83 mmscmd is the consumption. Source [17].

The Department of Fertilizer has indicated as against the actual supply of 22.10 MMSCMD gas to the fertilizer sector in 2001-02, the total gas requirement in 2006-07 would be 43.6 MMSCMD. The growth in gas demand would mainly come from additional supplies i.e. re-gasified LNG becoming available during the Tenth Five Year Plan Period for existing plants arid their expansions. The Rashtriya Chemicals and Fertilizers (RCF). Thal and KRIBHCO, Hazira plants would be taken up for further expansion, which would need 3.40 (MMSCMD) of additional gas supplies. Methane is the best-known feedstock for hydrogen production. Natural gas being highly rich in Methane enjoys an added advantage over naphtha.

Table 9.Cost and Efficiency Comparison for Producing 1 MT of Ammonia.

Feedstock	Energy	Variation %	Input-Output Norms (per MT)	Cost of feed stock Rs/unit	Feedstock cost per MT of ammonia produced	Variation%	Investment" (Rs in million)	Variation%
Natural Gas	7.85	-	0.86	3372	2900	-	563	-
Naphtha	11	40	0.90	6820	6138	112	617	10
Fuel Oil	13.78	76	0.90	5010	4509	55	804	43
Coal	26.6	239	3.62	2500	9050	212	1340	138

SOURCE: Department of fertilizers, Govt. of India.

The feedstock policy for nitrogenous fertilizers had either to envisaged establishment of new plants based mainly on natural gas. Works are in progress for setting up of an integrated chain of LNG supply in the country.

3.2 NATURAL GAS IN COMMERICIAL SECTOR

Cooling

This may be space conditioning and refrigeration. The usage is increase, depending on site of utilization.

Food Services

Restaurants can use natural gas for food services. It will provide better temperature control, speed, and efficiency in cooking.

Hotels

The usage of natural gas will provide a better humidity control and a desire for efficient structure.

Health Care

Gas can also be used in hospitals for captive power generation, cogeneration, and gas cooling application office Buildings The usage of Gas in office building is to design efficient heating and cooling systems with reduced operational cost.

Retail Building

They can be used for water heating, cooling and cooking.

Residential Usage

- It costs 30% less than that of electricity per BTU
- It is used in heating and cooling
- Provides complete combustion
- Has a good calorific value
- Can be used in air conditioning of residence

3.3 NATURAL GAS IN TRANSPORTATION SECTOR

Natural gas has long been considered an alternative fuel for the transportation sector and is being practiced for the past eight decades. According to the Natural Gas Vehicle Coalition, there are more than 1.5 million Natural gas vehicles worldwide. In recent years, technology has improved to allow for a proliferation of natural gas vehicles, particularly for fuel intensive vehicle fleets, such as taxicabs and public buses. The stringent environmental norms make the usage even more significant.

Being a relatively clean fuel with lower / nil emissions levels of Sox, NOx and SPM, natural gas in its compressed form is being promoted by the government as a fuel for the transport sector vide sales tax exemption and a lower custom duty of 5 per cent on imported CNG kits as against a peak fate of 25 per cent. CNG as an automobile fuel improves engine efficiency. When CNG and air in the right proportions are brought together, they mix thoroughly and rapidly, thereby improving the combustion efficiency, while the engine stays clean internally. The running cost of CNG is lower compared to diesel and gasoline. The maintenance cost is also low due to better fuel quality.

CNG has already replace approximately 5J I 1\1 (kilolitre) diesel and 315 Id of petrol in Delhi. In Mumbai CNG has replaced 102 Id of diesel and 350 kl of petrol. However, It is difficult to co-relate the value of petrol and diesel vis-à-vis quantity sold in the last three years because of frequent price revision in petrol and diesel.

Characteristics of CNG vis-à-vis Petrol

CNG has a much higher-octane value than petrol, making it a superior fuel. Due to the absence of any lead content in CNG the lead fouling of plugs is eliminated. Being gaseous fuel. CNG mixes with air easily even at very low temperatures.

Delhi's paradigm shift to CNG.

To establish the feasibility of using CNG as an alternate fuel to the polluting conventional fuels, a pilot study was conducted by GAIL (India) limited in Delhi, Mumbai and Vadodara in collaboration with the Dehradun -based Indian Institute of Petroleum (IIP) In 1992-93. The study firmly established CNG as a suitable alternative to conventional vehicular fuels such as petrol and diesel and effectively removed all apprehensions with regard to the handling, transportation, storage, and usage of CNG. GAIL put the date generated in to actual practice in 1997 with dawn of Delhi City Gas Distribution Project. Subsequently acquired by IGL in 1999 the project covers the laying of natural gas pipeline network for piped natural gas distribution and creating CNG infrastructure for distribution of CNG to automobiles in the national capital region of Delhi.

Starting with nine CNG stations IGL has grown substantially, As on June 30, 2003, IGL's number of stations stands at a praiseworthy list of 113 CNG stations in a matter of just four years. Among the nine CNO stations that GAIL set up us part of the pilot programmer of the Delhi City Gas Distribution Project in 1997 were Mother Station, three Online Stations, and five Daughter Stations. The 113 stations consist of 54 Mother Station, 20 Online Stations, 30 Daughter Booster Stations and 9 Daughter Stations, These stations with a compression capacity of 14.86 lakh kg/day cater to 82,127 vehicles ranging from buses light goods vehicles (LGVs), rural transport vehicles (RTVs), auto rickshaws, mini buses, tourist taxies, Phatphat Sewa Vehicles, private vehicles, and the like.

Private vehicle owners are finding CNG to be highly advantageous and rewarding since it allows attributes of both CNG and petrol to power a vehicular engine with just a flip of u switch. While it has already been established that CNG is non-toxic (it being free of Lead and Sulfur), it is also a 'green fuel'. Being non-corrosive, it enhances the longevity of' spark plugs. Due to the absence of any lead or benzene content in CNG the lead fouling of spark plugs and lead or benzene pollution on are eliminated. Another practical advantage observed is the increased life of lubricating oils as CNG does not contaminate and dilute the crankcase oil. The operational cost of vehicle, running on CNG as compared to those running on other fuels, is comparatively low

For its success, IGL was even lauded the selection of Delhi for the 'Clean City International Award" by the Department of Energy of the Government of United States in May 2003. The award Was conferred on Delhi for becoming the first city in the world to shell Its complete-Public transport system from petrol und diesel to CNG completely to reduce pollution for reducing the pollution in the city. The results of the CNG drive are evident the pollution levels showing substantial downturn, the air becoming cleaner and people feeling the difference. Delhi's selection for this prestigious award is encouraging and has provided a model for the introduction of natural gas as a favorable fuel for transportation sector.

Chapter 4

Natural gas : supplies

HIGHLIGHTS

- Gas production in 2004-05 was about 32 BCM (87 MMSCMD).
- However, ONGC's gas production, which is 73% of domestic gas production, is projected by them as to stagnate at about 23 BCM between 2004-05 and 2010-11.
- On the other hand gas production by OIL is likely to increase from 2BCM in 2004-05 to 3.8 BCM by 2010-11.
- Fortunately, several significant new discoveries have been made off the east coast.
- Gas production by Pvt/JV companies (including ONGC JVs) is is projected to increase from 6.7 BCM in 2004-05 to 23.4 BCM by 2010-11,an increase of 16.7 BCM.
- Of this, 14.6 BCM (40 MMSCMD) is expected to contribute by RIL from 2008 onwards.

5.1 Indigenous supplies.

In natural gas front demand India has various opportunities to the industry players gas demand is rising fast, as India develops more gas-fired power station, fertilizer sector is not lagging behind and taken an positive step to sift from naphtha to natural gas for feedstock by 2007.there fore from only 0.63tcf in 1995,natural gas demand is expected to rise to 0.96 tcf by 2010.

Table 10. demand of natural gas .

Year	Demand (in MMSCMD)
2006-2007	231
2011-2012	313
2024-2025	391

Source : Hydrocarbon Vision 2025.

The major concern Indian Natural Gas industry is continuous supply of natural gas.the total indigenous production of natural gas is 90 mmscmd. However a lot of gas lost during extraction and what is available is much less. The availability for market ,including what we are importing in the forn of LNG is only 83 mmscmd as against the demand of 155mmscmd. A shortfall of almost 50% and with time this shortfall will rise continuously.for this reson only ,India has made major efforts to fuel this rising demand, New Exploration Licencing Policy,(NELP) actually took off in the 1997-98 fiscal,gaining momentum by end-1998 and has become the prime mover scince 2000 in attracting investments in exploration,as a result we had marked some great discoveries in Indian history, RIL's 7 tcf and GSPCL's 20 tcf in KG basin, able to supply 40 mmscmd and 65-70 mmscmd consequently ,a sum total of 105-120 mmscmd gas supply .if we add this to the total production of gas now which is 87mmscmd the supply would be 200 mmscmd. That is not sufficient enough to meet the demand.Thus it's mandatory for India to develop its nonconventional source of natural gas, CBM AND HYDRATE.

CBM, an alternate source of clean and unconventional energy,is primarily methane gas in its natural state in coal or lignite bed seams. Oil majors such as ONGC,OIL,GAIL,RIL are planning to begin CBM production by 2010.with coal resevers of 400 billion tonnes in country, the CBM resource potential is estimated to be to the tune of 35 –45 tcf.

In gas hydrate front huge reserves are available in deepwater's of India , with huge potential reserves it would be a major source of natural gas supply in near future. (See table 11)

Table .11 Estimates Gas Hydrate Resources of India.

	Probability of equal to or greater than				
Plays	95	75	50	25	5
Bombay offshore	135	307	454	630	852
Kerala konkan offshore	62	221	1137	1566	2299
Northern Arabian Sea	226	440	595	789	1092
Southern Arabian Sea	0	0	312	709	1094
Eastern offshore	1038	1527	2168	3181	4525
Northern bay of Bengal	245	334	486	648	937
Southern bay of Bengal	188	367	1022	2468	3773
Total reserves (tcm)	1894	3196	6156	10000	14572
Total reserves (tcf)	66290	111860	215460	350000	510200

Source: [18]

4.2 Imported natural gas.

As in near future our indigenous supply of natural gas is not sufficient to fuel the growing gas demand we have to look outward and think seriously for natural gas import. Import can be done in two ways either through pipelines or in the form of LNG.

5.2.1 India's some of the proposed pipelines routes.

Oman-india deep-water pipeline-capacity=56.6 mmscmd.

Problem: in order to avoid the territorial waters and the exclusive economic zone of Pakistan, a deepwater route has proposed. In 1994 this pipeline was proposed but it was felt that there is no appropriate technology is available to lay this pipeline. As a consequence this pipeline proposal has not been pursued further moved further .

Iran- India pipeline. Capacity 60mmscmd further rais to 90 mmscmd for India. Feasibility study were carried out by National Iranian Oil Company and BHP of Australia .problem –despute between India and Pakistan over the Kashmir issue and terrorism that India is not able to take a strong decision for the pipeline. But no as Pakistan has also joining the hands for this pipeline and agrred to pass this pipline through its territory we seen it sooner or later.

Turkmenistan-India via Afghanistan and Pakistan. Capacity=40 mmscmd. Proposed by UNOCAL. Problem: political instability of Afghanistan and the unsolved issues between Pakistan and India, UNOCAL has withdrawn from the project. However, in resent time again USA is pushing is ahead as it will help Afghanistan to rebuild it self after the war (Afghanistan getting a good sum of income through transit fee).

Qatar- India- proposed by the Crescent Company of Sharjah. while the project appears viable, the same problems exist and an early solution is unlikely.

Myanmar -Bangladesh –India. Capacity =40 mmscmd,14 mmscmd from banladesh and rest is from Myanmar. Proposed by Unocal and Shell.however the Bangladesh government is unwilling to export the gas ,reason given is that they don't have enough resource of natural gas to meet its own industrial energy demand for the next five decades.

4.2.2 LNG import projects – existing and proposed.

Petronet (Dahej in gujarat and cochin in kerala) – started in 2004, capacity initial 5mmtpa now grown up to 10mmtpa.

Pipavav,Gujarat- BG international has been interested in developing this terminal.problem BG is anable to procure gas for this project.

Hazira, Gujarat – capacity-5mmtpa. Shell has developed this facility and supplying gas to the western region of india, but as it is getting its LNG from the spot market , it is supplying gas at the price of USD 7-8/MMBtu ,which has not been supported by the conservative and price sensitive consumer ,as a result facility has kept idle.

Jamnagar, Gujarat. Proposed by RIL. Negotiating a head with Qatargas for the purchase of 5mmtpa of LNG.

Trombay, Maharastra. Capacity 3mmtpa. Proposed by the Indian natural gas company (INGC), with equity participation by GAIL, TotalfinaElf, and the Tata Electri Company. INGC has had discussion with TotalfinaElf to buy gas from Yemen and also had discussions with QatarGas.

Dabhol, Maharastra. A Govt. of India, initiative. Capacity –5mmtpa. Working started as a Rratnagiry power corporation ltd.even not get its first supply of LNG.

Ennore,Tamil Nadu. Capacity 2.6mtpa.proposed and planned by Dakshin Bharat Energy Consortium with Unocal, Siemens, Woodside. Signed MoU with RasGas of Qatar.

Kakinada, Andhra Pradesh. Capacity 2.5 mmtpa. Planned by IOC, BP and Petronas.still in a very early stage of development.

From the above discussion it is clear that all the up coming project for natural gas import is stuckup either because of financial-technical or geological problem. Will see more in the next chapter which route is viable for India pipeline or LNG with the help of international experience in this segment.

Chapter 5

LNG v/s Pipeline-Options and risk.

5.1 INTERNATIONAL GAS TRADE - The rise in international gas trade

The geographical mismatch between resource endowment and demand means that international trade should witness a sustained expansion in the next thirty years, and that the main growth markets for gas are going to become much more dependent on imports. International trade already represented 682 10^9 m^3 in 2001, and could approach 1300 10^9 m^3 in 2020, about 30% of world production and 1700 10^9 m^3 in 2030 (Figure 6.1). In absolute terms, the biggest increase in imports is projected to occur in

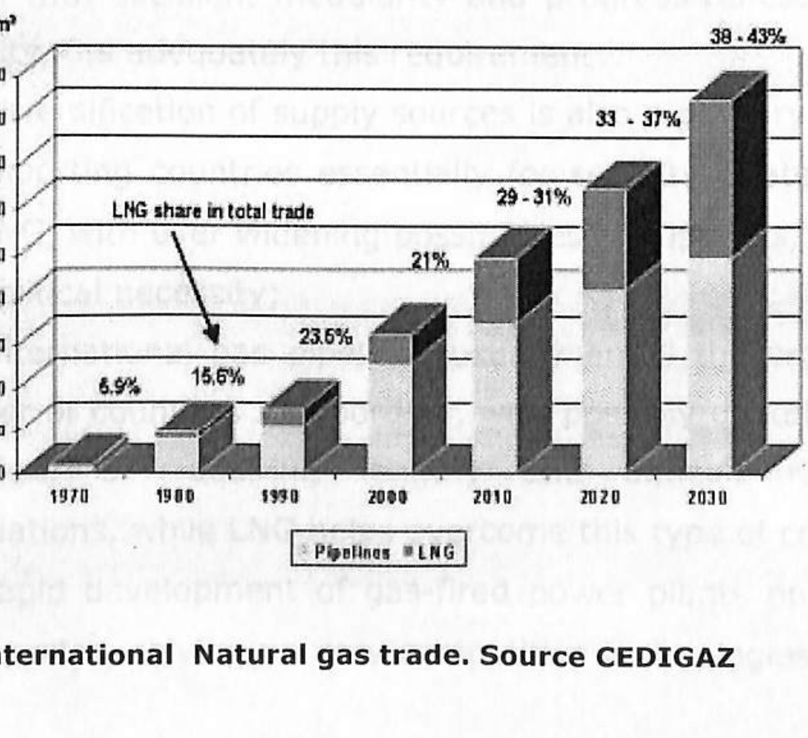


Figure 22. International Natural gas trade. Source CEDIGAZ

5.2 LNG versus pipelines

There is only two ways of transportation of natural gas, which are technically and economically feasible. So far, pipeline flows between countries or continents have largely dominated the international gas trade. It suffices to recall that LNG only accounts for 22% of international trade (only 5.6% of world natural gas demand). However, the rebalancing of natural gas markets, via gas pipelines, is often faced with technical, economic, even political limitations:

1. The growing geographic distance from the discoveries and hence reserves to the large consumer zones may result in physical or technical/economic impossibilities for international gas pipelines;
2. Some of the major traditional exporting countries via pipeline (Canada, Netherlands), should be approaching their maximum export capacity limit in the next ten to twenty years;
3. The new importing countries, mostly emerging countries, located far from the pipeline networks, seek supplies adapted to their highly localized and fast growing needs. LNG, a maritime option with excellent modularity and progressiveness in project capacity, fits adequately this requirement;
4. The diversification of supply sources is also a primary concern of the importing countries essentially for security related reasons, and LNG, with ever widening possibilities of suppliers, also meets this political necessity;
5. The international gas pipelines usually entail the crossing of a number of countries and borders, with possibly unstable political situation, or requiring lengthy and difficult right-of-way negotiations, while LNG helps overcome this type of constraints;
6. The rapid development of gas-fired power plants on coastal or nearby sites, relying on very competitive technologies, obviously

offers a huge market for LNG projects: several dozen potential projects combining LNG receiving terminals and gas-fired power plants are currently on the design boards throughout the world;

7. The general trend of liberalization of energy markets is causing the breakup of the traditional industrial structures, the diversification of contractual forms, and the proliferation of players and trading flows, particularly for gas and electricity. This should favor the growth of independent LNG import terminals.

Therefore the LNG trade should expand rapidly in the next decades. Total LNG trade was 143 10^9 m^3 in 2001 (137 10^9 m^3 in 2000) corresponding to less than 3 million barrels a day, with twelve importing and twelve exporting countries. LNG flows have doubled in the past decade and are expected to experience strong growth in the coming years, with LNG trade estimated to rise to approximately 300 10^9 m^3 by 2010 and 700 10^9 m^3 by 2030.

6.3. ECONOMICS OF PIPELINE AND LNG TRANSPORTATION

The transportation segment, either by pipeline or by LNG tankers requires large, up-front investment. Gas transport costs easily exceed half of the gas market value and so far only 22% of gas crosses borders whereas 57% of oil does so. Gas projects are also characterized by long lead times as more than 10 years may elapse between the conception of a project and its first revenues, increasing financial risks associated with it.

The economics accordingly represents the main milestone in the setting up of an import scheme and, although it is the unique parameters of each project which will finally determine where the economic breakeven point between transportation by pipeline or LNG tanker will be for a specific gas source and its markets, a number of general factors, be it technical, economic or political, always apply in the choice of any large gas export scheme.

This section analyses current cost for pipeline transportation and LNG. It is drawn on the World Energy Outlook 2001 (WEO 2001), which analyses energy supply issues.

6.3.1 Economics of pipeline transportation

Large-diameter and long-distance pipelines imply very high capital investment. They require both large, high-value markets and substantial proven reserves to be economically viable. Capital charges typically make up at least 90% of the cost of transmission pipelines. The key determinants of pipeline construction costs are diameter, operating pressures, distance and terrain. Other factors, including climate, labor costs, the degree of competition among contracting companies, safety regulations, population density and rights of way, may cause construction costs to vary significantly from one region to another.

Pipeline operating costs vary mainly according to the number of compressor stations, which require significant amounts of fuel, and local economic conditions, especially labor costs. In designing a pipeline, the optimal mix of diameter and compression capacity will depend on the expected load factor. Once a pipeline is built, the average cost per unit of throughput will depend almost entirely on the average rate of capacity utilization. A high level of utilization with a high load factor is usually critical to the economic viability of the pipeline.

Globally, the investment required to lay a long distance, large diameter line (46 to 60 inches), enabling a throughput of about 15 to 30 10^9 m^3/year, currently amounts to $1 billion to $1.5 billion/1000 km. The Alliance Gas pipeline between Canada and US for instance (36 inch of diameter, 3686 km long, operated at 120 bar) cost about US$3 billion. Investing for subsea lines are much higher, depending on water depths.

Because pipeline transportation is less complex than the LNG process, cost reductions have been less impressive. However, substantial improvements have been achieved in optimizing project design and construction, inspection activities, laying and welding methods, steel quality and weight, thus reducing material costs and the period of construction. Increased competition among inspection-service companies also contributed to reduce the overall cost.

Developments over the past decade in *offshore pipeline technology* have contributed to lower unit costs and have made possible deep-water projects that were previously impossible. The development of a pipe-laying technology capable of laying pipes at 650 metres depth represented a breakthrough in the early 1980s and allowed to lay the Transmit pipeline between Tunisia and Sicily. Offshore pipeline technology also played a big role in the exploitation of North Sea gas resources in the 1970-80s and those more recently in the Gulf of Mexico.

One of the methods most commonly used to install marine pipelines is the S-lay method. This production process leads to a very fast laying rate even when handling large diameter pipes, from 2 up to 6 km / day. For greater depths and larger diameter pipelines the main alternative to S-lay is the J-lay method. It is based on applying the axial force in a near-vertical direction, virtually eliminating any horizontal reaction on the vessel equipment. The most recent example of the J- lay method is its recent application to the construction of the $3.2 billion Blue Stream Project, designed to deliver Russian gas across the Black Sea to Turkey.

As installation and intervention works represent about half of the cost to lay a pipeline over a difficult seabed, these developments have contributed to lower unit costs and have made possible deep-water projects that were previously impossible.

5.3.2 LNG economics

LNG projects are very much capital intensive. The cost of the entire chain from wellhead to the receiving terminal can be around US$4 billion. As in the case of pipelines, economies of scale are very significant:

Liquefaction plants typically consist of one or two processing trains. The economic size of each train is now about 3 to 3.5 million tonnes per year. With this size of project, the capital cost of just the LNG production facility is in the $1-2 billions range. Adding a second train once a plant is built can reduce the overall unit cost of liquefaction by 20-30%. A single-train plant normally costs around $1 billion, although actual costs vary geographically according to land costs, environmental and safety regulations, labour costs and other local market conditions.

Technological progress achieved in the past decades has led to a sharp decrease in investment and operating costs of liquefaction plants. The average unit investment for a liquefaction plant dropped from some $550 a ton a year of capacity in the 1960s, to approximately $350 in the 1970s and 1980s, and $250 in the late 1990s. For projects starting operation today, the price is slightly under $200 (all in current dollars).

Transport costs are largely a function of the distance between the liquefaction and regasification terminals and the size of the vessel. Using a larger number of smaller carriers offers more flexibility and reduced storage requirements but raises unit shipping costs. The largest LNG carriers today have a maximum capacity of 135,000-138,000 m^3. They cost around $170 million to build. Substantial reductions in cost have been achieved over the past decades thanks to economies of scale. Tanker sizes have increased from some 40,000 m^3 for the first generation to a range of 130,000 to 140,000 m^3 nowadays.

Regasification plant construction costs depend on throughput capacity, land development and labour costs (which vary considerably according to location), and storage capacity. Economies of scale are most significant for storage. These are maximised for storage tank capacities of about 150,000 m^3 – the largest feasible at present.

The last five to ten years have seen some major reductions in LNG supply costs. These have come largely from increases in train size, improved fuel efficiency in liquefaction and regasification (mainly from high-efficiency gas turbines in on-site co-generation facilities), improved equipment design, the elimination of gold-plating and better utilisation of available capacity. Liquefaction costs have fallen typically by 25% to 35% and shipping costs by 20% to 30% from 1990 to 2000. The cost of regasification has fallen less than costs for the other parts of the LNG chain since the 1960s. Technology and productivity gains have been largely offset by higher storage costs, the largest single cost component.

Table 12: Cost reduction in the LNG chain (Middle East to Far East LNG project) in $/millionBtu

	Cost estimate Early 1990s	**Cost estimate Early 2000s**
Upstream development cost	0.5 - 0.8	0.5 - 0.8
Liquefaction	1.3 -1.4	1.0 - 1.1
Shipping (LNG tanker)	1.2 - 1.3	0.9 -1.0
Regasification	0.5 - 0 6	0.4 - 0.5
Total cost	**3.5 - 4.1**	**2.8 - 3.4**

Source: TotalFinaElf, Gaz de France and Cedigaz, WEC, 2001

LNG costs vary considerably in practice, largely as a function of capacity, particularly the number of trains in liquefaction plants and shipping distance.

6.4. PIPELINE COST REDUCTION

Worldwide transportation grid (national and international) has expanded from about 725,000 km in 1970 to 1,100,000 km in 2000. The vast majority of the worldwide grid is concentrated in three regions: North America, Europe and FSU. In North America, the grid was already largely developed in the 1970s, whereas it expanded quickly in Europe (central and western) from 91,000 km in 1970 to 255,000 km in 2000, and in the FSU: from 68,000 km to 225,000 km in 2000. Most of the transportation grid has been developed for intra-regional trade. The interregional gas pipelines supply only one area: Central and Western Europe from the FSU and Africa.

In the next 30 years, according to the IGU report on Trade and Investment, the lengths of the gas transmission pipeline networks may more than double, with contrasting prospects in the different world regions. In South Asia, in the Middle East and in East Asia, the lengths currently in place will increase seven-fold. Two thirds of the 1,400,000 km of additional networks will be laid in three areas: North America (500,000 km), FSU (240,000 km) and Central & West Europe (170,000 km). This development will call for investments ranging from US$ 240 to 600 billion over 2001 - 2030. Improvement to the transport technology is the key for extending the world-wide gas grid. In the past, the progress has been most rapid in offshore pipeline technology. New technologies have been developed, including automatic laying methods, the use of high tensile steels and high-pressure transport. Such technologies may be progressively applied also onshore, with a significant impact on the development of an interconnected grid at the intercontinental scale. Cost reductions can be expected from stronger steels, high-pressure technology, and deepwater pipe laying. *High pressure (HP) technology* is expected to play a major role in reducing the unit cost of large-scale, long-distance pipeline projects. HP technology is more economic than conventional technology for an annual throughput capacity of more than 10 109 m3, and its competitiveness improves linearly with capacity. Cost savings for a transmission system of 5,000 km with a capacity of 15 to 30* 10^9 m^3/ year, are estimated at 10% to 30%. By increasing the operating pressure two benefits can be expected. With the same cross section, the transport capacity increases while the friction losses, referred to unit of mass transported, are reduced. The importance of cost reductions can be illustrated by the example of a large diameter pipe connecting Turkmenistan to Europe, as investigated in the study "Gate 2020" prepared by ENI and IFP for the European Community. The transportation cost is represented as a function of the gas flow-rate in figure 6.2.

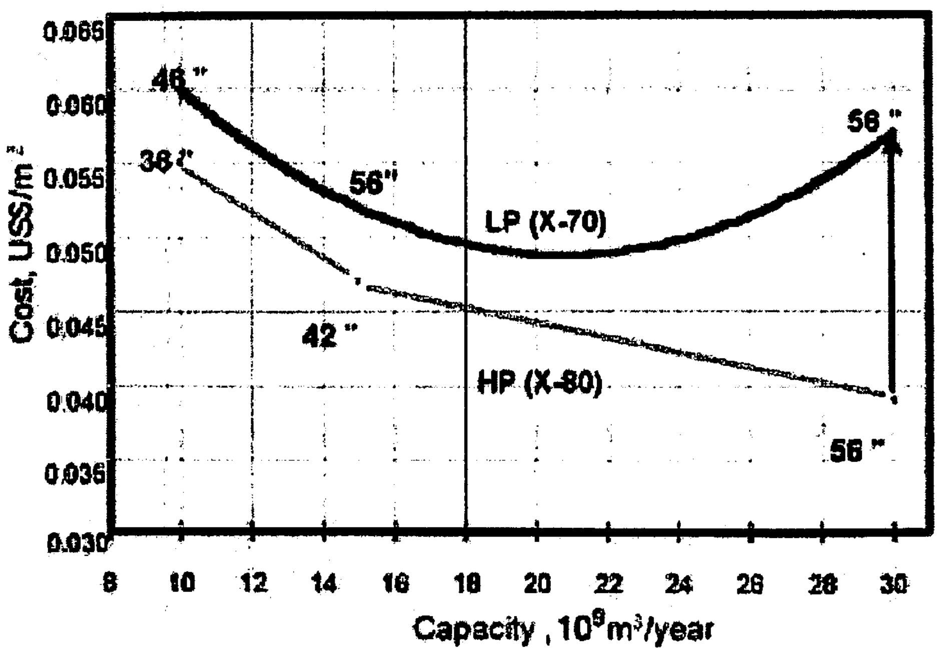


Figure 23. Long distance transportation cost for a large gas quantities, source IFP

In this example it has been shown that very substantial cost reductions can result from the choice of a high pressure transport option, using an X-80 steel instead of an X-70 steel, at a lower pressure. The future use of very high strength steel API 5L X-100 could permit further reduction of transportation cost, by cutting CAPEX and OPEX.

Gas pipeline systems are expected to remain the basic transportation system for intra-regional trade (North America, Europe, South America). Some major trunk-lines linking production areas with the expanding markets, are expected to be characterised by:

- Very large capacity, from 15 to 30 10^9 m^3/year;
- Long distances;
- Geological complex and challenging environments.

High-pressure pipelines are the only solution capable of reconciling the transport requirements with the reduction of the transportation costs. According to the Gate 2020 Survey, further progress in deep-water pipeline technology can be expected in the following areas:

- The use of higher grade steels, which reduce pipeline weight (and therefore the amount of steel required) and make pipe-laying quicker and easier;
- Improved manufacturing processes, including sophisticated computer techniques for optimising pipe design criteria that allow for reduced pipe-wall thickness and material cost savings;
- Large-diameter pipeline-laying techniques such as J-laying, which reduces the curvature of the line and, therefore, stress during laying allowing the use of lighter pipes;
- High Frequency Induced (HFI) pipes, an alternative to seamless pipes, which can be up to 30% cheaper due to reduced construction and welding costs;

- Advanced seabed-surveying techniques, which permit optimisation of steel weight, concrete coating and trenching for pipeline stability.
- Improved insulation to reduce hydrate problems.

Practical examples of the application of these advances include the Blue Stream pipeline under the Black Sea, which was commissioned at the end of 2002. This project involved the construction of two parallel lines across the sea at a maximum depth of 2,150 metres. Water depths in the range of 3000 to 3500 m seem accessible in the near future. These advances will lower supply costs and contribute to a growing interconnection of the pipeline grid. Some important subsea projects currently envisaged could benefit from these new developments.

Table 13. Major long-distance gas pipelines planned or under study (onshore and offshore)

Route/Pipeline	Capacity (10^9 m^3/year)	Length (km)	Estimated cost (billion US$)
Africa to Europe			
Libya to Italy (GreenStream)	8	570	
Algeria to Sardinia (Italy)	8	1470	
Algeria to Spain (Medgas)	8	747	
Nigeria-Niger-Algeria-Europe (Trans-Saharan)	18	4000	
FSU to Europe			
North TransGas	Up to 30		
Yamal-Europe II	2 x 33		4107
Turkmenistan - Turkey - Europe	28	3000 - 4500	3.5 - 5
FSU to Asia			
Irkutsk Basin (Kovykta) - China - S.	About 35	4000 to	15 - 20

Korea		5000	
Sakhalin - China (Shenyang)	10	2420	4
Sakhalin Island – Japan (either via Niigata or through the Pacific coast to Tokyo)		8	
Western Siberia – Xinjiang - Shanhai	30	1870	4
Turkmenistan - China (Xinjiang/Shanghai)	25	2150	5
Turkmenistan – Pakistan (via Afghanistan)	15	1500	1.9
Kazakhstan – China (Shanghai)	25	3370	5
Middle-East to Europe			
Iraq - Turkey	15 - 20	1383	
Middle-East to Asia			
Iran to India via Pakistan	18 20	3300	5
Qatar – Pakistan (GUSA)	16.5	1600	3.5
Africa (intra-regional)			
Mozambique – South Africa (Pande Project)	1.5	905	0.7 - 1.0
West Africa Gas Line (Nigeria-Ghana-Togo-Benin)		3400	4
Middle-East (intra-regional)			
Qatar – Abu-Dhabi - Dubai (Dolphin project)	21 (1st phase)	1600	
South-East Asia (national and intra-regional)			
West-East China Pipeline (Xianjiang to Shanghai)	12.4	2400	
Indonesia's South Sumatra - Singapore	3.7	500	
Gulf of Thailand - peninsular Malaysia - Singapore – Sumatra -Java		2000 - 2500	

Source: CEDIGAZ

5.5. <u>LNG COST PROSPECTS</u>

Further advances in LNG technology can be expected in liquefaction and shipping, which could lead to lower overall project costs. Further cost reductions efforts primarily target the liquefaction unit itself, which represents around half of the total investment cost and secondly the tankers. The regasification terminal, which represents only 10 % of the overall cost, should however be concerned by any of these progresses.

5.5.1 Liquefaction cost reduction

Cost reductions in *liquefaction* are currently focused on increasing economies of scale from larger train sizes. Several planned plants, such as Melkoya Island in Norway, Gorgon in Australia and the Gulf of Paria in Venezuela, have train capacities in excess of 4 106 ton/year. The additional train planned for the RasGas plant in Qatar will have a capacity of 4.7 106 ton/year. Capacities on planned new trains for the Qatargas' plant range from 5 106 ton/year (TotalFinaElf) to 7.5 106 ton/year (Exxon Mobil). These capacities, which could reduce unit construction costs by 25% compared to 3 106 ton/year trains, should become feasible within the next few years. Further improvement in fuel efficiency and unit investment costs can be expected from larger gas turbines as train size increases. Optimisation of design parameters, improved reliability, closed-loop cooling systems, the exploitation of cold-recovery and new heat-exchanger designs under development could yield further cost reductions, as well as better engineering and bidding processes, especially for extensions of existing liquefaction plants. Cost reductions will also result from the use of new equipment and more efficient processes. These trends can be illustrated by considering the economic benefit resulting from the use of IFP developed Liquefin process as compared with an older still commonly used technology. Such a comparison is presented in Table 6.3.

Table14. Economic comparison: Liquefin vs C3/MR process

	C3/MR	Liquefin	Liquefin vs. C3/MR
Equipment cost (million$)	129.8	112.1	-13.6%
Installed equipment (million$)	259.7	258.2	-12.7%
Capacity (10^6 ton/year)	3.85	4.48	+16.4%
Specific investment	76.6	57.6	-25%
Total investment	868	823	-5%
Total specific investment	225	184	-18%

Source: IFP

As compared with a standard C3/MR process, the Liquefin process makes it possible to achieve an investment cost reduction of around 20% per ton of produced LNG, with a reduced operating cost. An other significant advantage is the possibility to achieve very large capacities for a single train, 6 Mt per year and higher.

5.5.2 FPSO units

In the longer term, Floating Liquefaction Storage and Offloading (FLSO) plants, where processing and storage facilities are based on a vessel moored offshore in the vicinity of the producing fields, could reduce costs even more and make the development of some small and remote gas reserves or deep offshore gas feasible.

This technology can reduce costs by minimising the cost of offshore platforms and pipelines, eliminating the need for port facilities and reducing the time needed to build the plant. Construction can be carried out in a low-cost location and the vessel transported to the production zone. FLSO plants can also address problems that arise when siting facilities onshore. Investors may see them as less politically risky in some countries. A number of technical and safety issues will need to be addressed before FLSO technology can be deployed commercially. It is thought likely at present that FLSO plants will be best adapted to small capacities and medium-sized offshore fields in remote locations. The technology could therefore compete with GTL projects. FLSO plants are under study in Australia (Gorgon and Bayu Undan) and in Angola. Recent progresses, such as cryogenic flexible pipes for LNG loading/unloading should contribute to make this option economically feasible in the near future.

5.5.3 <u>Shipping costs</u>

The potential for *shipping* cost reductions is mainly confined to further increasing carrier size. The next generation of LNG carriers, now under development, will have a capacity of 165,000 m^3, which would yield modest economies of scale. Carriers of up to 200,000 m^3, which could potentially reduce unit costs by 10% compared to the current maximum size of 140 000 m^3, are being considered. The main obstacle to increase furthermore the capacity to that size is the port capability to receive such tankers (problems of draft).

5.5.4 <u>Regasification costs</u>

The membrane technology can largely be applied to the regasification terminals. LNG storage is the largest single cost in the terminal (from 40 to more than 50 % of the total direct costs depending on the site). It usually represents twice the tanker size in terms of volume. Therefore, any incentives aiming at decreasing costs should be considered. Even if today most of the onshore storage are based upon the self supporting tank technology, the membrane technology can bring significant cost reductions. In addition to a better space optimisation, it offers several other advantages like safety in case of leakage, particularly for buried storage.

5.6 LNG VERSUS PIPELINES

5.6.1 Indicative pipelines and LNG costs at full utilisation.

The changes in costs also affect the relative attractiveness of the pipeline and LNG options. In determining the most economic transportation method for a given supply route, distance and the volumes transported are the key factors. For short distances, pipelines – where feasible – are usually more economic. LNG is more competitive for long distance routes, since overall costs are less affected by distance. The normal breakeven distance for a single-train LNG project against a 42" onshore pipeline (not allowing for transit costs) is around 4,500 km at a cost of around $1.60/millionBtu. The breakeven point has tended to fall over the last decade, as LNG costs have fallen faster than pipeline costs. But technology advances have made possible short-distance offshore pipelines where previously LNG had been the only viable option. For large deliveries (around 30 10^9 m^3/year), the transport of gas by HP pipelines appears very much competitive (Figure 6). For long distances, LNG appears competitive for capacity below 10 10^9 m^3/year. For Middle East supply to Europe for instance (between 4,500 and 6,000 miles), the LNG allows a cost saving of up to 30% with respect to HP pipe technology. Therefore, LNG could be preferred for small fields exploitation on a long distance transportation (Figure 7).

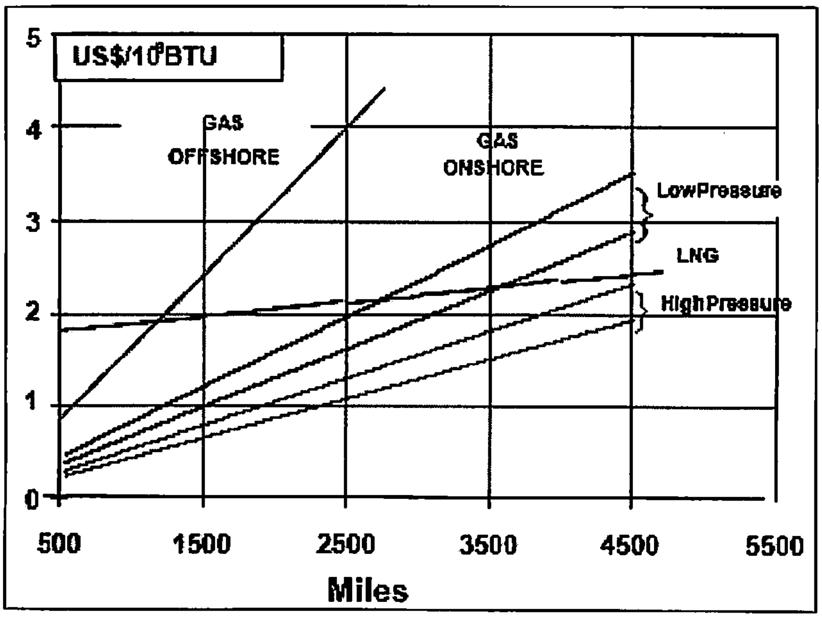


Figure 24 Pipes /LNG competition for 30 $*10^9$ m^3 /year capacity. Source ENI.

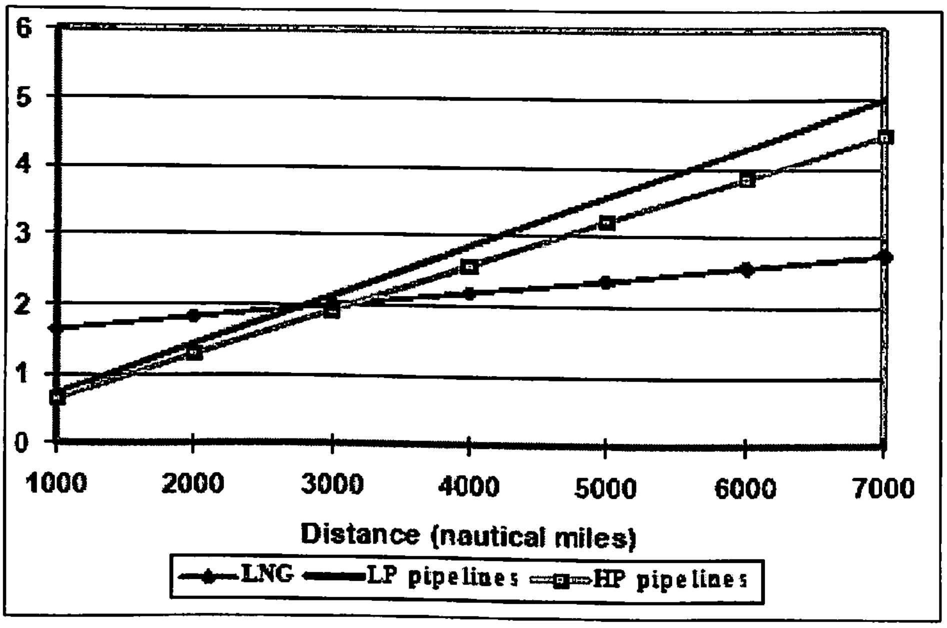


Figure 25 Pipes /LNG competition for $10*10^9$ m^3 /year capacity, in USD / MM BTU

In practice, however, LNG projects do not often compete directly against pipeline projects for the same supply route. Competition to supply a given market is usually between different supply sources, either by pipeline or LNG. For example, Trinidad LNG competes against Algerian gas supplied through the Maghreb pipeline to Spain.

5.6.2 Influence of Market and Financing Factors

However, besides the economics – at full utilisation - of each solution, there are three main elements that influence the specific costs as shown on the graphs:

- Utilization/market size
- Financing conditions
- Development of level and size of investment

The development of the three elements has favoured the economics of LNG versus pipeline, shortening the breakeven distance:

- The new projects on the markets are much smaller than they were in the 1980s. Huge projects, like Troll in Norway or SoyuzGasexport or Yamal delivering Russian gas to Europe with 20 or more 10^9 m^3/year are increasingly rare today. Projects of 5 10^9 m^3/year are more typical. However the levelized cost shown on the graphs is based on a throughput of 10 to 30 10^9 m^3/year.
- At a 5-10^9 m^3/year throughput, specific pipeline transportation costs are much higher than indicated by the line representing the cost of a 42-inch onshore pipeline.

- Financing of LNG is lower risk (e.g. Oman LNG with an A- rating by Standard & Poor's).

In the case of pipelines, each country border and ethnic enclave crossed adds to the risk premium, which increases the levelized costs. In addition, evolution of investment costs is coming down more favorably for LNG than for pipelines, where cost reductions are mainly linked to an increase in capacity that is difficult to absorb by the market.

For smaller projects to fit into more competitive markets or markets that start with a small bankable demand, LNG should be more attractive than pipeline gas even at much shorter distances (2,000 to 4,000 km).

5.6.3 Geographic and political factors

However, as noted before, not all gas-producing countries have a choice. Russia and most FSU countries are landlocked and will depend on pipeline gas exports with, maybe, the exception of gas from Sakhalin. The long distances separating gas producing countries or regions and major consuming centres are generating the need for high-capacity gas pipeline systems. This also applies for North American and South American intra-regional trade. For gas exports from South America to North America, the LNG option seems preferred.

North Africa has a pipeline option to the European Union and an LNG option to the United States. For small distances, such as linking Libya to Italy or Algeria to Spain, the pipeline option will be preferred. For longer distances, Nigeria to Europe, the two options compete. However, so far only the LNG option has been developed.

For Middle East the pipeline option might be advantageous to supply Turkey and Europe onwards. A link is already operating between Iran and Turkey. Exports to Pakistan by pipeline may also be considered. For political reasons, LNG is currently the obvious export route for Middle East gas to India. . Moreover, with lower costs for LNG, the Middle East is well-placed to supply LNG to OECD Europe, OECD Pacific, and even OECD North America. Qatar is a frontrunner on this in expanding its LNG plants. Iran is also planning to export LNG.

In Asia/Pacific, due to geographic considerations, LNG dominates. The pipeline option should emerge in the medium term. Certainly, new links between neighbouring countries could in the long run enable the development of an integrated gas grid in the region. In the Indian SubContinent, although pipe option should be certainly the more economic, political considerations so far have impeded this development and favoured the LNG option. The opposite applies to China, where political factors have favoured the development of an East-West pipeline. However, the LNG option is also in progress. The transport of gas by pipeline will maintain a primary role in the intra-regional gas trade. Despite the development of intercontinental gas pipelines, LNG should play a growing role in inter-regional trade. It allows supply diversification and provides increased flexibility in gas trade.

5.7 NEW TECHNOLOGIES

5.7.1

CNG and hydrates LNG and pipelines are not the only options to transport natural gas. New developments (Coselle, Enersea...) are under way, using dedicated gas carriers to transport Compressed Natural Gas (CNG). The CNG technology may have the potential to challenge LNG transportation for some niche markets, namely for short distances and small markets (such as the Caribbean market, for instance). However, the feasibility and economics of this new technology still needs to be tested. Another option which is also explored, with similar purposes, consists in transporting natural gas in the form of hydrates.

6.7.2

Gas-to-Liquids Technology As the outlets for the LNG and GTL chains are completely different, their markets appear complementary rather than competing. LNG is aimed at gas markets, while GTL is meant for a fuel market. The approach taken in this section is therefore not to compare the cost of GTL versus LNG, but rather to consider GTL as an alternative way of exploiting gas reserves in remote gas rich areas where no local market exits. Advances in technology, increases in reserves in remote locations and higher oil prices have recently stimulated a surge in interest in developing GTL projects. GTL plants produce conventional oil products as well as specialist products. All the plants already in operation, under construction or planned are based on the Fischer-Tropsch technology originally developed in Germany in the 1920s. Recent technical advances, including improved catalysts, have significantly improved liquid yields and reduced both capital and operating costs. GTL technology is now seen as a potential alternative to LNG as a way of exploiting gas reserves in remote locations. Three commercial scale GTL plants in the world have been designed and built under special economic circumstances: Mobil MTG in New Zealand, Mossgas in South Africa and Bintulu in Malaysia. The technology has now reached a decisive turning point. Two commercial plants - one already fully financed - are moving forwards to scheduled on stream dates in 2005; Qatar is evaluating a raft of proposals for GTL plants based on competing technologies; and projects are under active study in seven other countries. Shell plans four 75,000- barril per day (b/d) plants, possibly in Egypt, Indonesia, Iran and Trinidad and Tobago. Output of liquids from GTL plants is projected to jump from 43,000 b/d now to around 300,000 b/d by 2010 and 2.3 million b/d by 2030. These projections are highly dependent on oil-price developments and the successful demonstration of emerging technologies. Beyond 2010, GTL plants could potentially lead to the development of a large volume of gas reserves. In WEO 2002, global GTL demand for gas is projected to increase from 4 109 m3 in 2000 to 21 109 m3 in 2010 and 170 109 m3 in 2030. The rate of increase in GTL production is nonetheless subject to enormous uncertainty, particularly after 2010.

The economics of GTL processing are highly dependent on plant construction costs, product types and yields and the energy efficiency of the plant, as well as the market prices of the liquids produced and the cost of the gas feedstock. GTL plants are complex and capital-intensive, requiring large sites and construction lead times of two-and-a-half to three years. They are also very energy-intensive, consuming up to 45% of the gas feedstock. This characteristic raises concerns about CO_2 emissions. On the other hand, GTL plants generally produce a range of middle distillates with good environmental qualities, demand for which is rising.

Capital costs typically account for at least half of total levelised costs for an integrated plant with power production on site. Syngas production accounts for about 30% and the Fischer-Tropsch synthesis process itself about 15% of capital costs, with other processing units, power generation and other services making up the rest.

GTL-production costs have fallen sharply in recent years, largely due to improved yields and thermal efficiency. The latest GTL technologies being developed by Shell and Sasol, a South African energy company, are thought to involve capital costs of around $20,000 b/d of capacity. A 75,000-b/d plant would, therefore, cost about $1.5 billion, nearly twice as much as a modern oil refinery. But GTL can yield a better return on investment than can oil refining if the cost of the natural gas feedstock is significantly lower than that of crude oil. Shell claims that its Middle Distillate Synthesis technology is profitable at a crude oil price of $14/barrel, assuming low gas-field development costs and no penalty for carbon emissions.

Large-scale commercial development of GTL technology will depend on achieving higher yields of readily marketable products such as gasoline and middle distillates, with lower yields of speciality products, for which markets are limited. The viability of GTL may also be dependent on the absence of any penalty for carbon emissions.

The economic competitiveness of GTL plants can be improved by using a more cost effective technology for the three main sections of the plant: synthesis gas production, Fischer-Tropsch synthesis and fuels upgrading by hydrocracking. It can be improved also by increasing the producing train capacity. A steady decrease of the investment cost related to the output can be observed, at a rate which is around 10% per year. Following this trend, an investment level below 15 000 $/b/d can be expected within the ten coming years, which will improve further the profitability of these plants.

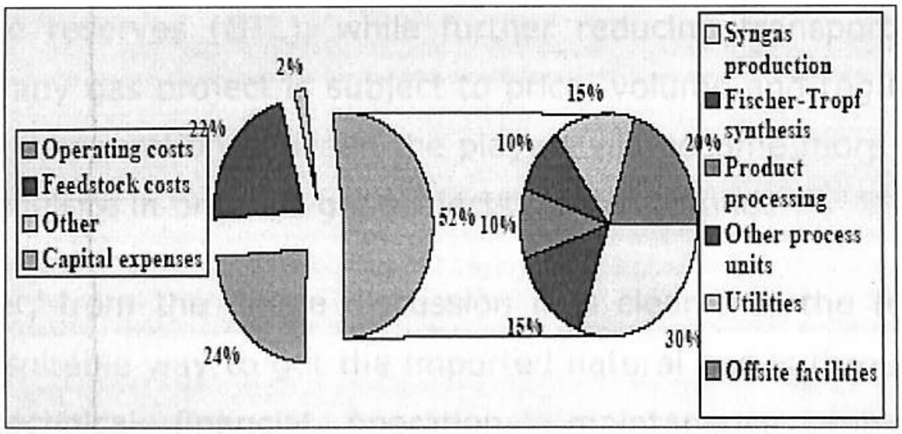


Figure 26 ***Note:*** **Based on a 30,000 b/d plant built on a coastal site. Levelised cost is $18/barrel of product output.**
Source: Foster Wheeler Energy Ltd, cited in Ghaemmaghami and Clarke (2001).

In practice, GTL is likely to compete for investment funds against both oil refining and alternative ways of exploiting gas reserves. GTL may be the preferred option for "stranded" gas reserves, where the cost of piping or shipping the gas as LNG to markets are prohibitive.

5.8. CONCLUSION

In the years to come, supply cost reduction will be more vital than ever in the highly competitive export markets that lie ahead. The development of gas markets and the new liberalised environment mean that often small, incremental projects will be favoured instead of big projects, which could benefit economies of scale but would not fit with the development of gas markets. Therefore, very often, when competition will exist between pipeline and LNG, the LNG option will be the preferred one, thanks to its flexibility. Nevertheless, a major part of trans-national trade will be only feasible by long-distance gas pipelines.

Major cost reductions in transportation of gas and LNG are still expected and in particular for HP long-distance pipelines. This should enable a spectacular development of cross-border gas trade. However, the industry is increasingly looking for additional ways to monetize remote reserves (GTL), while further reducing transportation costs. While any gas project is subject to price, volume and regulatory risks, closer co-operation between the players will become more than ever a pre-requisite in order to get projects off the ground.

Further, from the above discussion it is clear that the for India the most suitable way to get the imported natural gas is through pipeline. The technical, financial, operational, maintanence problem we can solve on our own, but not the geopolitical problem. Therefore even though it has shown that pipeline is the viable route ,but the risk associated with it is a lot, and if we decided to go for offshore pipeline the cost of gas is crossing the curve of LNG import cost and even if we decided to lend the gas in form of LNG , decision is not support to do so because the international prices(USD 9-10 per MMBtu)of LNG has gone very high, not supporting the Indian consumer to think about it.

chapter 6

Forecasting and Model.

6.1 Why forecasting is essential.

Its human tendency that he always tries to find out the scene that lies with future. The energy sector is also don't have escape from this tendency and with the present scenario its very essential to know the probable possible scenario's. Here we require a forecasting methods, models that able to tell as the future scenario as our policy makers goal is to secure the continuous supply that will need in the future. In India many firms are busy with this task. The result of these efforts are Hydrocarbon Vision 2025, Indian Vision to be a energy independent nation by 2030,Intregated energy policy, Projections for our domestic production of any commodity (like oil, coal, natural gas etc), Green house gases impact projection 2100 etc. These all policy's and vision need a model based on which a probable scenario is forecasted and thus a required, needed and essential steps have taken.

We to here, to forecast the natural gas demand, for the year of 2050 used a model called "KGKPG Model"(development stages and description is given in section 7.2).

6.2 Hero of the research topic- THE KGKPG MODEL.

KGKPG means "KNOWN GDP AND KNOW POPULATION GROWTH" . **The M**odel is based on a Japanese model, which is developed by the Institute of Energy Studies Japan to study the impact of CO2 emission in the atmosphere in 2100, an ultra long-term scenario, and developed by the experts from that institute. An extensive study has been done by them and the way they connected the entire dependent and independent factor, which should consider in the model, is really interesting is really interesting.

The Model, which has presented here, is conceptual model & it is not a mathematical model and the creator of this model is not an experienced one in this segment. Here I tried to make the simplest model to eliminate the complexity and can forecast the demand of gas for 2050. Complexity as had been told in the last line is because of many reasons and in other horizon I can say that will act as a variable for the function called "limitation". So my limitations for the model is many and will frequently discussed where ever it is needed in model development stage 7.3.

6.3 Natural Gas Demand model KGKPG- Description & Development.

All model's which I have gone through have two integrated level: at the first level (aggregate), total energy demand, measured in suitable convertible units, as a function of population, GDP, Per capta income, reference year, year at which the forecasted data is needed, price of the energy, international practice standard and benchmarks for energy use has estimated. At the second level (disaggregated), market shares held by each energy source (coal, electricity, natural gas, oil, nuclear, hydro etc are made functions of corresponding market share and of relative price with environmental considersion and policies. the second task is most difficult and required a high level of analysis and experience. I eliminate this step to make model a simple one and assumed that natural gas will constitute of 30% of total commercial energy demanded in year 2050 (base to made this assumption is not on relative price based of fuel but international practices, environmental consideration and technologies to exploit hydrate and coal bed methane by that time.

Development steps:

1) Total energy demand is a function of population, GDP and elasticity.

$$\Phi = f\ (P_t,\ GDP_t,\ \varepsilon_t)$$

2) Population on the corresponding year is a function of population in previous year and population growth rate.

$$P_t = f\ (P_{t-1},\ p_{gr})$$

3) GDP at the corresponding year is a function of GDP at previous year and GDP growth rate.

$$GDP_t = f\ (GDP_{t-1},\ GDP_{gr})$$

4) GDP and energy consumption is related with demand elasticity.

$$\varepsilon_t = (\%\ \Delta\Phi)_{\Delta t} / (1\%\ \Delta GDP)_{\Delta t}$$

4) Elasticity is a function of human development index(HDI), International practices, price of energy etc etc . and its difficult to present it in a mathematical form here.

5) Symbols represents:

Φ = Total energy demand for year t.

P_t = population in year t.

P_{t-1} = population in previous year.

ε_t = elasticity in that corresponding year.

p_{gr} = population growth rate.

GDP_{gr} = GDP growth rate.

GDP_t = GDP at corresponding year.

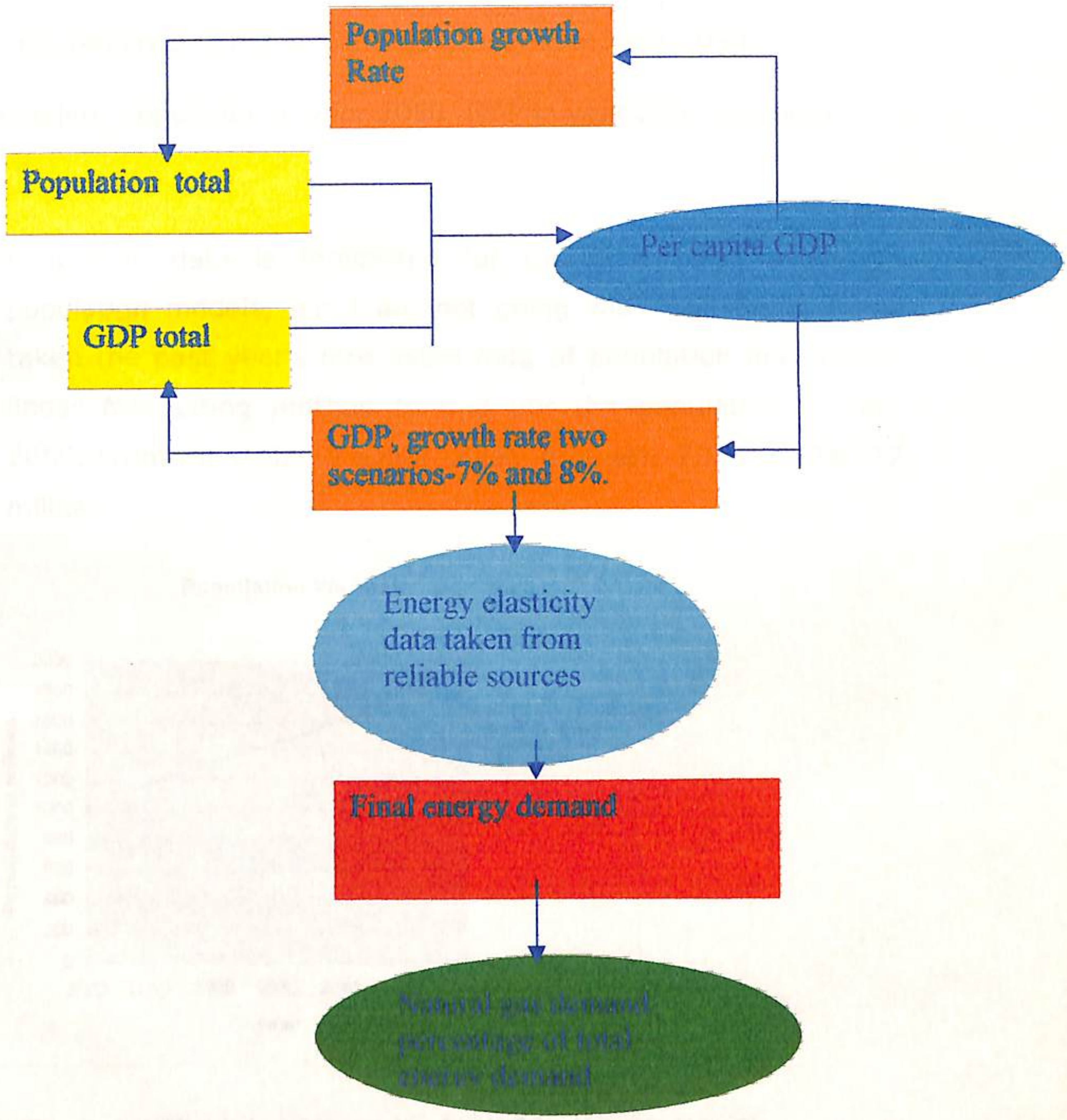
GDP_{t-1} = GDP at previous year.

$\% \Delta\Phi$ = Percent change in energy consumption.

$\% \Delta GDP$ = percent change in GDP.

Δt = time difference between t and t-1.

6.4 Model flow chart



6.5 MODEL SAMPLE CALCULATION

Task: it is required to find out the gas demand in year 2050.

Data needed: population in year 2050, GDP in year 2050,elasticity.

Steps:

1) Population data is forecasted for the year 2050 based on population models, but I am not going with this model I had taken the past year's forecasted data of population and used a linear forecasting method to find out the population in year 2050. From the below graph population in year 2050 is 1749.12 million.

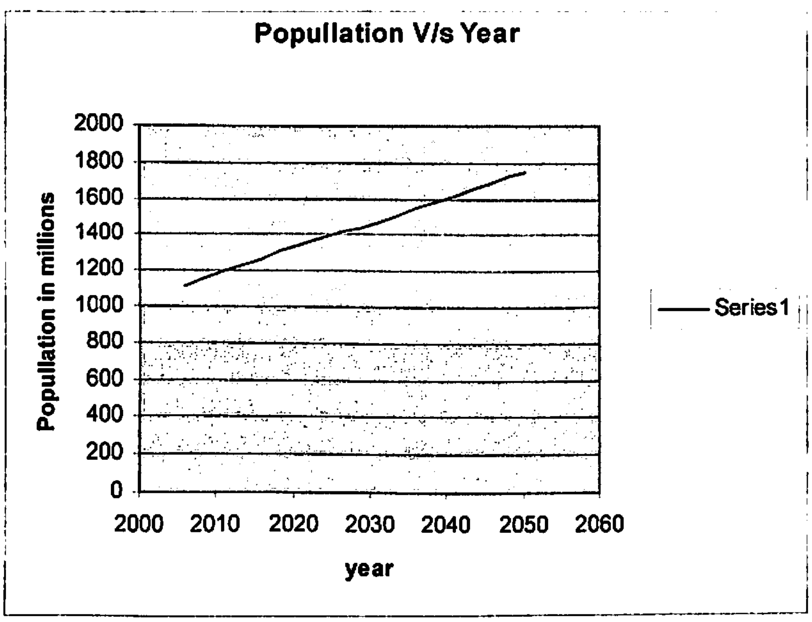


Figure 27. Population v/s year graph, SOURCE : KGKPG MODEL generated data.

2) For GDP data in 2050 we do the similar calculation but here I assumed 7% GDP growth rate (table has given for both 7% as

well as 8% GDP growth rate) and from the past data simply applied a compound interest formula as given

$$GDP_{2050} = GDP_{2045}(1+R/100)^{N}$$

Where R = 7 (assumed), N = no of years here 5.

From graph below GDP at 2050 is Rs. 36775697.21 crore.

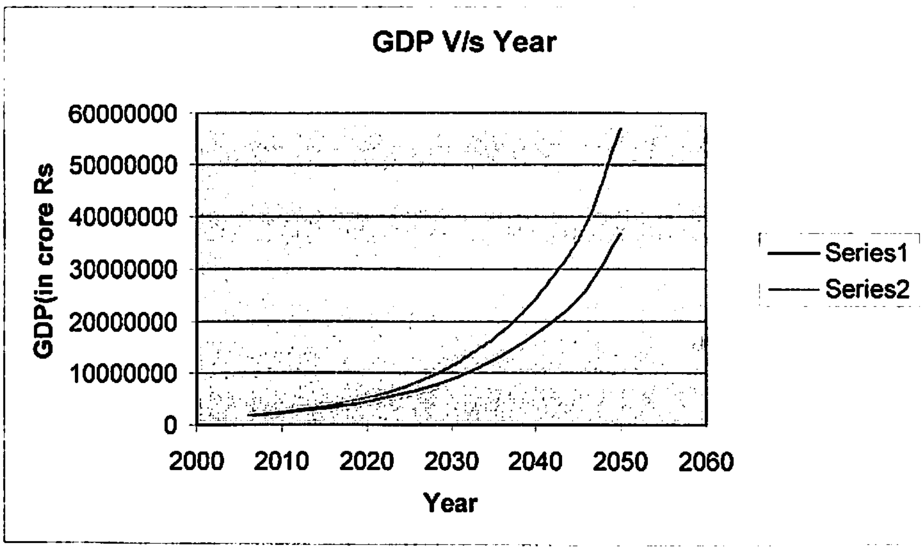


Figure 28. GDP v/s year graph, series 1 for 7% CAGR and series 2 is for 8% CAGR. SOURCE: KGKPG MODEL generated data.

3) Percent increase in GDP

% in GDP = (GDP in 2050-GDP in 2045) *100 /(GDP in 2045)

= 40.25517 %

4) GDP per capita for that year is

=(GDP in year 2050/population in year 2050)

=Rs 210252.5684 /capita.

5) Elasticity, I have taken two values in this report as suggested by "INTEGRATED ENERGY POLICY", 0.8(constant elasticity), 0.67

(falling elasticity). Results are shown for both this values in the table below but here taken the falling value 0.67.

6) 0.67 means, for 1% change in GDP, energy consumption will change by 0.67 %. So as we know the total GDP change that is 40.25517 %.

For 1% GDP change ≅ 0.67 % increase in energy consumption

∴ For 40.25517% GDP change = 40.25517*0.67

= 26.97099 %.

7) Now, the energy required for year in 2050 is

= Energy in 2045(1+% increase in energy consumption/100)

= 2847.03(1+26.97099/100)

= 3614.904272 mtoe (million tonnes of oil equivalent).

8) However, the natural gas demand is, as earlier told also find out as the share of the total energy demand based on many parameters and variables but here I had assumed that Indian policy makers had correctly forecasted it .20% of total energy demand by year 2025 and with this same progression I assumed that it will go up to 30 % by 2050 of the total demand (supported by high oil price, environmental pollution, new discoveries, hydrate, CBM etc.).

Natural gas demand = 3614.904272*30/100

= 1084.471 mtoe.

9) This is Model generated data so I had also t o consider the error to find out the actual demand for year 2050.

10) Error here is defined as

$$\% \text{ Error} = (TPES_{mgd} - TPES_{act}) * 100 / TPES_{act}$$

11) But as we don't know the NGD_{act}, neither we know the error , so we have to generate a function based on previous data that will give the value of error for the year 2050.for that propose I had plotted the %Error V/s Total energy demand data, then find out the curve best equation ,then further calculate the % error for the year 2050. From the fig. Below the best suit function is linear one i.e. y=-0.0043x + 1.4418, as R2 ≅ 1(0.9926) as compared with the log equation where R2=0.9892.

12) As we know the error function putting x = 3614.904272 mtoe, we get the %error for the year 2050 y=-14.10228837%.

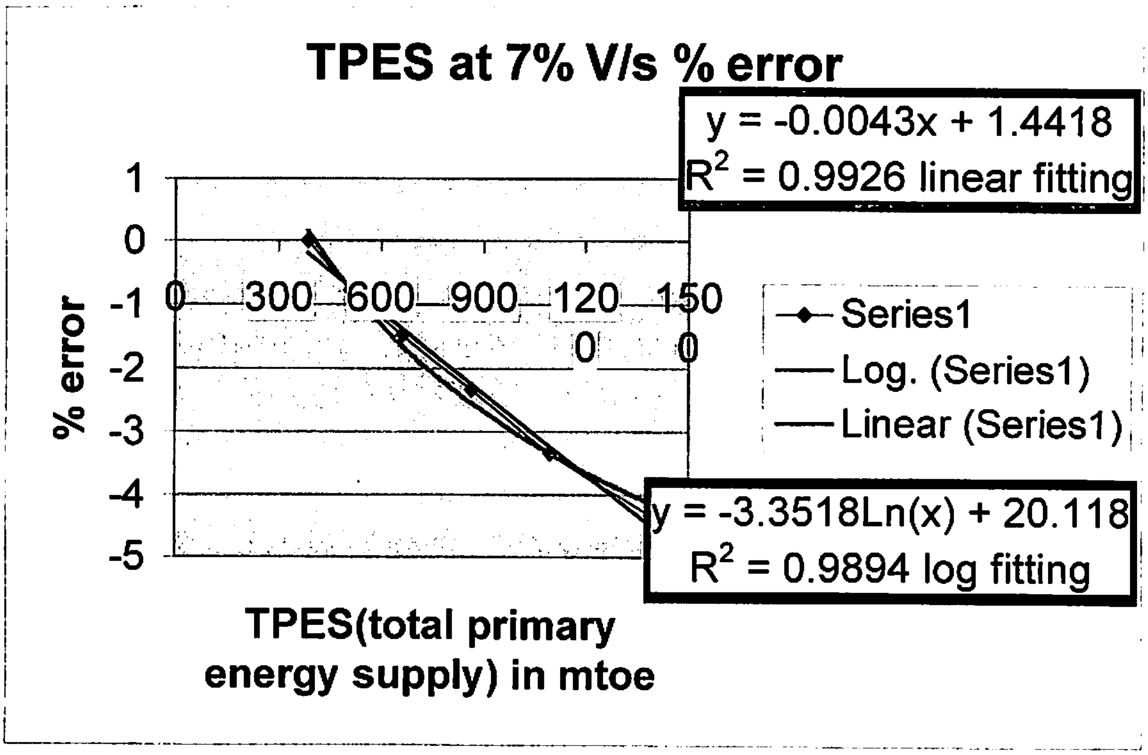


Figure 29. Total demand of energy V/s % error

13) Now, from the formula,

$$\% \text{ Error} = (TPES_{mgd} - TPES_{act}) * 100 / TPES_{act}$$

We can back calculate the NGD_{act}

$$NGD_{act} = NGD_{mgd} / (1 - \% \text{ Error}/100)$$

$$= 3168.12007 \text{ mtoe.}$$

14) However, the natural gas demand is, as earlier told also find out as the share of the total energy demand based on many parameters and variables but here I had assumed that Indian policy makers had correctly forecasted it .20% of total energy demand by year 2025 and with this same progression I assumed that it will go up to 30 % by 2050 of the total demand

(supported by high oil price, environmental pollution, new discoveries, hydrate, CBM etc.).

Natural gas demand = 3168.12007 *30/100

= 950.436018 mtoe.

15) 950.436018 mtoe when converted in to B Cu m(Billion cubic meter)=1054.98596 B Cu.m. Demand for year 2050. (1 mtoe equals to 1.11 BCum of natural gas)

The International Energy Agency (IEA) recently completed a detailed study of energy investment requirements out to 2030. Total estimated investment requirements total US$16 trillion, or one percent of world gross domestic product. Oil accounts for $3.1 trillion, with conventional oil production accounting for the bulk of the investment at $2.2 trillion, and an additional $205 billion needed for nonconventional oil. The investment needs of tankers and pipelines amount to $260 billion, while $410 billion is needed for refineries, predominantly in the Middle East, Africa, and Asia.

6.6 Model results.

	Year	Population in millions	Population growth rate	GDP (Rs. In crores)@ 1993-94 prices@7%	% Increase in GDP
Data taken	2006	1114		1751019	Base year
From	2011	1197	7.450628366	2455891	40.25496011
integrated	2016	1275	6.516290727	3444520	40.25541036
Energy	2021	1347	5.647058824	4831117	40.25515892
Policy	2026	1411	4.751299183	6775892	40.25518322
document	2031	1468	4.039688164	9503539	40.25517231
	2036	1550.4	5.613079019	13329205.07	40.25517307
Forecasted	2041	1621.371429	4.577620522	18694899.64	40.25517307
By	2046	1692.342857	4.377246775	26220563.85	40.25517307
Me	2050	1749.12	3.354943274	36775697.21	40.25517307

GDP (Rs. In crores) @ 1993-94 prices @ 8%	% Increase in GDP	GDP per capta @ 7%(Rs/capita)	GDP per capta @8%(Rs/capta)
1783901	Base year	15718.30341	16013.47397
2621137	46.93287352	20517.05096	21897.55221
3851310	46.93280054	27015.84314	30206.35294
5658837	46.93278391	35865.75353	42010.66815
8314688	46.93280616	48021.91354	58927.6258
12217004.53	46.93280768	64738.00409	83222.10169
17950787.77	46.93280768	85972.68493	115781.6548
26375596.47	46.93280768	115303.0041	162674.6099
38754404.43	46.93280768	154936.476	228998.5405
56942934.53	46.93280768	210252.5682	325551.9034

Falling elasticity	Constant elasticity	% Change in consumption with falling elasticity for 7%	% Change in consumption with constant elasticity for 7%
0.8	0.8	Base year	Base year
0.8	0.8	32.20396809	32.20396809
0.75	0.8	30.19155777	32.20432829
0.75	0.8	30.19136919	32.20412714
0.67	0.8	26.97097276	32.20414658
0.67	0.8	26.97096545	32.20413785
0.67	0.8	26.97096596	32.20413846
0.67	0.8	26.97096596	32.20413846
0.67	0.8	26.97096596	32.20413846
0.67	0.8	26.97096596	32.20413846

TPES at 7% FE (MODEL DATA) mtoe	TPES at 7% with FE (actual) mtoe	% Error	Share of natural gas in% of total demand	Natural gas demand mtoe
385	385	0	7	26.95
508.9852771	505	-0.789163791	15	75.75
662.6558611	653	-1.478692363	15	97.95
862.7207386	843	-2.339352149	20	168.6
1095.404914	1060	-3.340086227	20	212
1390.846195	1333	-4.339549502	20	266.6
1765.970849	1663.626624	-6.151874649	20	332.7253248
2242.270245	2072.339216	-8.199962053	25	518.0848039
2847.032189	2569.51347	-10.80043841	30	770.8540409
3614.904272	3168.126007	-14.10228837	30	950.437802

Year	Natural gas demand mtoe	Natural gas demand in B Cu.m
2006	26.95	29.9145
2011	75.75	84.0825

2016	97.95	108.7245
2021	168.6	187.146
2026	212	235.32
2031	266.6	295.926
2036	332.7253248	369.3251105
2041	518.0848039	575.0741323
2046	770.8540409	855.6479854
2050	950.437802	1054.98596

6.7 Model conclusion.

With 7% GDP growth rate natural gas demand will be 1054.98 B Cu.m.

Chapter 8

The End statement

7.1 Brief discussion on what we had covered.

From the above all chapters it is clear that, natural gas, as a commodity, has got an intensive attention from whole world. Its reserves have grown up by 86% over the last 20 years. Developing countries has also started looking toward this source of energy.

India 's demand of natural gas is continuously growing as India will grow with 7-8% it also wants that it should also take part in the league of environmental friendly nation by being signing the Kyoto protocol sooner or later. Therefore, it is essential for Indian energy policy makers to think it of right now & should go for environmentally friendly fuel and natural gas is suggested as a one of the cleanest fuel available in the earth.

India's demand for the natural gas for 2050 will be 1054.98 B Cu.m.

But its not the easy task for our energy policy maker to get it. Policy, technology, infrastructure should be made or developed to get better acceptability of natural gas as a commercial fuel among Indian citizen's. Then only we cannot blame by our next generation that our ancestors has given as a cleanest environment and then only it suites the statement-21st century belong to natural gas.

7.2 In what way India will get its natural gas-still a question?

We had also experienced in some of the previous chapter's that India's indigenous gas production is only 30-40% of total natural gas demand, not sufficient to fulfill the natural gas demand on our own. We have to outward and should go for natural gas import. There are only two ways now technically and economically feasible either by LNG or by pipeline. In case of LNG the price of it had impacted in a very bad manner to all India's LNG proposed terminal. In LNG segment we have to require to go for long-term contracts and to secure a continuous supply of natural gas. In case of pipeline our relations with our neighbor countries are not good and it is essential for us to put more weightage on Indian subcontinent in our strategy and policy, to increase more trade with them and also support them in their development and these steps will help India to make a good relation with the neighboring countries and India will get a number of pipeline through them to fuel its growing economy, environment friendly & economically for the better tomorrow of India.

Reference:

1. Cedigaz (2002), *Natural Gas in the World – 2001 Survey*, Rueil Malmaison
2. Cedigaz (2003), *Online LNG Worldwide Statistics*, Rueil Malmaison
3. Cedigaz News Report, Rueil Malmaison, various issues
4. ENI/IFP (2001), *Gate 2020 – Gas Advanced Technology*, Brussels; CEC.
5. IGU (2003), *Report on Trade and Investments to 2030*, IGU Committee 9 (to be published in June 2003)
6. International Energy Agency (IEA) (2002), *World Energy Outlook 2002,* Paris: Organisation for Economic Cooperation and Development.
7. IEA (2002), Natural Gas Information 2002, Paris: OECD .
8. IEA (2002), Flexibility in Natural Gas supply and demand, Paris: OECD.
9. IEA (2001), *World Energy Outlook 2001 Insights-Assessing Today's Supplies to Fuel Tomorrow's Growth*, Paris: OECD.
10. World LNG Prospects: Favorable Parameters For A New Growth Era, 18th World Energy Congress - Buenos Aires - Argentina (October 21 - 25, 2001), VALAIS Michel, TotalFinaElf, France, CHABREL.IE Marie-Françoise, Cedigaz, France, LEFEUVRE Thierry, Gaz de France, France.
11. THE CHALLENGES OF FURTHER COST REDUCTIONS FOR NEW SUPPLY OPTIONS (PIPELINE, LNG, GTL) Sylvie Cornot-Gandolphe, International Energy Agency Olivier Appert, International Energy Agency Ralf Dickel, International Energy Agency Marie-Françoise Chabrelie, CEDIGAZ Alexandre Rojey,

Institut Français du Pétrole and CEDIGAZ *22nd World Gas Conference 1-5 June 2003, Tokyo, Japan.*

12. Draft report of the expert committee *on Integrated Energy policy, Planning Commission, Govt. of India.*

13. www.indiainfoline.com.

14. www.ey.com ,

15. www.assochem.nic.in

16. www.bp.com/statistical/review2005

17. www.eia.com

18. www.iea.doe.gov.com

19. www.crisilindia.com

20. www.pricewatercooperhouse.com

21. www.icraindia.com

22.

23. "Experts discussion changing dynamics Indian oil and gas business", *Mr. Anand Sharma, Minister of State for External Affairs ,Govt. of India. 6th Indian oil and gas conference. DEW JOURNAL April 2006.*

24. "NATURAL GAS IN ASIA-THE CHALLENGESOF GROWTH IN CHINA,INDIA,JAPAN AND KOREA".*page 73.published by the Oxford University Press.*