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REPORT ON GLOBAL WARMING AND ASSOCIATED IMPACTS

(PHASE V)

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REPORT ON GLOBAL WARMING AND ASSOCIATED IMPACTS

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Examining the Replacement of coal by natural gas in utility and industrial application

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Introduction

The current debate on climate change has resulted in the suggestion of several short term, no regrets measures to help alleviate the problem. One such measure that has gained considerable currency is that of substituting higher carbon fuels by lower ones. While the renewable energy technologies are the ultimate end, an intermediate solution lies in the increased utilisation of natural gas, thereby substituting fuels such as coal. The debate has generated sufficient controversy in India to require a detailed analysis in terms of reserves, utilisation, allocation between alternate end-users and the associated costs. This paper is a preliminary foray into this field; a more detailed analysis of several of the aspects covered is, however, required.

The paper is divided into 3 sections: the first discusses the allocation of natural gas in the market on the assumption that neither reserves nor capital are constraints. Some aspects, not adequately quantifiable at present, have been qualitatively discussed in the section. The cost of generation of electricity from coal and gas (open and combined cycle) based plants, and the value added/replacement value of natural gas use in the fertiliser industry are also touched upon. The second part deals with the reserves (in the Western and Southern regions of the country) and expected demand and supply of fossil fuels and electricity till 2010. Section 3 covers the environmental costs of changing the additional coal based capacity to gas based generation.

PART I

Natural gas occurs either as gas in underground reserves (dry gas or free gas) or can be liberated from crude oil (termed as associated gas). Methane is the dominant component and comprises 75 to 95 per cent of the gas. The remaining portion is made up of higher hydrocarbons such as ethane, propane, butane, in decreasing fractions. Natural gas can also contain some sulphur compounds, eg. hydrogen sulphide, and other contaminants such as carbon dioxide, nitrogen, water, trace metals, etc. Prior to use natural gas requires treatment and purification (termed as sweetening). Given that the fractioned liquids from natural gas fetch a higher price in the market than the gas itself, it lies in the interest of the producers of natural gas to pipe/distribute only the stripped lean gas.

Given the abundant reserves of coal in the country and the existing infrastructure for its extraction and distribution, it is unlikely that a widespread replacement of this fuel will occur in the near future. Further constraining the switchover to gas is the uncertainty surrounding the estimates of gas reserves, which makes it difficult to commit investment for its utilisation. Thus, for most regions where coal is easily available at a low cost, i.e. where the costs of transportation are not significant, it would remain the preferred fuel (assuming no pollution/carbon taxes are levied). However, in regions characterised by large industrial agglomerations and long distances from a coal source, alternate fuel sources would have to be considered on a priority basis. One state that does face such constraints is Gujarat. Given Gujarat's location - distant from coal sources but close to gas reserves - combined with the existence of several industrial towns, the continued use of coal from neither an economic nor environmental viewpoint can be justified. Hence, while a case for the increased utilisation of gas within the state can be made, the intersectoral distribution of the gas would have to be worked out.

For most regions, competitive claims would be made on the limited reserves of gas. In such regions or in regions where supply falls short of demand, allocation of the limited resource would be best achieved on the basis of the imputed value of the gas or value added. The imputed value of gas basically is the value of gas at which the cost per unit output from the gas based plant is equal to the cost per unit from a plant based on an alternate fuel/feedstock. In other words, it is the consumer's prices based on his willingness to pay. Despite the fact that the fertilizer and power sectors currently consume the bulk of the gas sold, several other end users, such as sponge iron units, are foreseen.

The estimate of the imputed value of gas depends on the distance of movement of the alternate feedstock/fuel and the consumption norms used. Hence, the imputed value of gas would have to be estimated on a location specific basis.

Review of Economic and Financial Costs of Natural Gas

Several estimates of the imputed value of gas for various end uses are available; some of which compute both the financial and economic replacement cost.

Sub group on natural gas availability, distribution and utilisation

The most recent estimate is that of the Report of the Sub-group on Natural Gas Availability, Distribution and Utilization, Eighth Five Year Plan (1990 - 1995). The sub-group estimated the imputed value of gas for the Bombay region. The results were as given below:

Table 1 : Economic replacement value

Use	Fuel Replaced	Price (Rs/1000 cu.m)
Peak load power	HSD	4337
Sponge iron (w quality improvement)		3700
Intermediate load power	HSD	3513
Peak load power	Naphtha	3502
Peak load power	Fuel oil	3000
Methanol	Naphtha	2813
Sponge iron (w/o quality improvement)		2770
Fertiliser	Naphtha	2728
Intermediate load power	Naphtha	2679
Base load power	Coal	2655
City gas distribution	LPG	2548
Intermediate load power	Fuel oil	2021

It can be seen that the maximum value added for gas is in its use for peak load power replacing fuels like HSD, naphtha and fuel oil. Use in the fertilizer sector, replacing naphtha has a higher value than the replacement of coal in base load power. If the above study were to form the basis for the distribution of gas, gas use would primarily be for meeting peaking power requirements. In regions where existing hydel capacity is limited or further expansion is constrained (eg. southern and, to limited extent, the western region), this might be useful, unless it replaces the existing hydel peaking capacity.

Kelkar Committee

The Report of the Committee on Pricing of Natural Gas, Department of Petroleum and Natural gas, May 1990 (also referred to as the Kelkar Committee Report) has calculated both financial and economic replacement costs of natural gas for 2 cases for fertilizer and power plants; Case I where both gas and coal based plants operate for 5500 hours per annum and the naphtha based fertiliser plants operate at 80 per cent efficiency; and Case II where gas based power stations operate for 7000 hours per year and the fertiliser plants operate at 90 per cent efficiency, as against 5500 hours for a coal based plant and 80 per cent efficiency for naphtha based fertilizer plants.

Table 2 : Financial Replacement Value of Natural Gas (1989 prices)

	Price (Rs/1000 cu.m)
Fertiliser	
Case I	2495
Case II	2951
Power	
Case I	
Pithead	1942
500 km	2503
1000 km	3024
Case II	
Pithead	2199
500 km	2760
1000 km	3280

Table 3 : Economic Replacement Value of Natural Gas (1989 prices)

	Price (Rs/1000 cu.m)
Fertiliser	
Case I	2784
Case II	3258
Power (coal)	
Case I	
Pithead	1917
500 km	2289
1000 km	2519
Case II	
Pithead	2196
500 km	2567
1000 km	2797
Power (fuel oil)	2082
Sponge iron plant	3760

For sponge iron plants, the economic replacement value is Rs.3760 per thousand m^3. Given that this is the highest (replacement) value, it indicates that adequate incentive exists to switch from coal to gas.

Given that gas stations do operate at higher efficiencies, the estimates derived in Case II appear to be more relevant. The results indicate that the replacement of coal in sponge iron plants is the most efficient, followed by naphtha in fertilizer plants and coal in thermal power stations.

Advisory group on perspective plan for natural gas

Based on the Advisory Group on Perspective Plan for Natural Gas, the imputed value (1990-91 prices) for natural gas in various end-use sectors was as given below:

Table 4 : Imputed Value of Gas (1990-91 prices)

Use	Fuel Replaced	Price (Rs/1000 cu.m)
Peak load power 1500 km	coal	2921
Base load power 1500 km	coal	2856
Peak load power 1000 km	coal	2761
Base load power 1000 km	coal	2610
Peak load power 500 km	coal	2600
Methanol	naphtha	2514
Fertiliser	naphtha	2466
Peak load power	naphtha	2407
Base load power 500 km	coal	2368
Peak load power	HSD	2296
Base load power pithead	coal	1975
Sponge iron	coal	1909
Peak load power	fuel oil	1776
City gas distribution	fuel oil	1708
CNG road transport	diesel	1154
Fertiliser import	urea	735

Assumptions for the above table:

1. Fertilizer consumption as per normative figures
2. For peaking stations, coal replacement also considered since coal based plants are run on partial load to meet the requirement.

This study is the only one to conclude that replacing coal by natural gas in base load generation would yield a higher imputed value to gas. All other studies recommend the replacement of coal by natural gas for peaking purposes. The next best option generally is the replacement of naphtha and fuel oil in the fertiliser sector.

Projects and Development India Limited

The most dated study on the economic price of natural gas was conducted by the Projects and India Development Limited (PDIL) in 1985. While, the study might not be of direct use in deciding the current economic replacement value of gas in different-end-uses, it could aid in the ranking of alternatives. Adopting this as a yardstick, however, assumes that inflation in all sectors has been uniform.

Table 5 : Economic Price of Natural Gas Rs./1000 m^3

	Natural gas	Naphtha	Fuel oil
Fertiliser	-	3080	4672
Thermal energy* use in			
(a) domestic and commercial	4461		
(b) industrial	2510		
Thermal power (captive)	3063		
Methanol	2977		
Hydrogen	2658		
Oxo alcohol	2651		
Utility power (CC)	2036		
Sponge iron	1986		

* for Vadodara

The study concludes that the most advantageous use of natural gas lies in its replacing fuel oil in the fertiliser industry. This is followed by substitution in the domestic and commercial sector, and then in the fertiliser industry, replacing naphtha. Replacement of coal in the utilities for base load generation yielded a lower value of gas than its alternate use in producing methanol.

Summary and critical analysis

Most of the estimates made in the various studies are limited by the paucity of firm cost data. Further, if environmental impacts are also included, i.e. ash disposal problem that arises from coal combustion, the replacement values, for cases where gas replaces coal, could be expected to increase.

Table 6 : Comparison of the Studies (Rs/1000 m³)

Use	Fuel Replaced	VIII plan (current 1990-91 prices)	Kelkar committee (1989 prices)	Advisory group (1990-91 prices)	PDIL (1985 prices)
Peak load power	HSD	4337		2296	
Sponge iron (w quality improvement)		3700	3760	1909	
Intermediate load power	HSD	3513			
Peak load power	Naphtha	3502		2407	
Peak load power	Fuel oil	3000	2082	1776	
Methanol	Naphtha	2813		2514	2977
Sponge iron (w/o quality improvement)		2770			1986
Fertiliser	Naphtha	2728	3258	2466	3080
Fertiliser	Fuel oil				4672
Intermediate load power	Naphtha	2679			
Base load power pithead	Coal	2655	2196	1975	2036
City gas distribution (domestic and commercial)	LPG/ fuel oil	2548		1708	4461
Gas distribution (industrial)	LPG/ fuel oil				2510
Intermediate load power	Fuel oil	2021			3063
Hydrogen					2658
Oxo alcohol					2651
CNG road transport	diesel			1154	
Fertiliser import	urea			735	
Peak load power 1500 km	coal			2921	
Base load power 1500 km	coal			2856	
Peak load power 1000 km	coal			2761	
Base load power 1000 km	coal		2797	2610	
Peak load power 500 km	coal			2600	
Base load power 500 km	coal		2567	2368	

All the studies reveal higher economic prices of natural gas substituting naphtha in fertiliser plants as compared to replacing coal at pithead power stations. However, it only the Advisory group that suggests that replacement in coal based power stations 1000 kms away from the coal source has a higher economic value. Economic prices arrived at by the various committees appear to show consistency for substitution options like naphtha in fertiliser plants. This, however, has to be viewed in light of the fact that the costs have been arrived at for different years and a true comparison would involve bringing all prices to a common base. This requires the development of inflation indices for all the uses of natural gas, something beyond the purview of the study.

A point to note is that since the cost of coal varies with the distance over which it is transported (as against a flat rate for gas supplied through the HBJ pipeline), the cost of (electricity) generation is sensitive to the distance over which the coal is transported. A 10 per cent change in capital costs of transport infrastructure is estimated to result in a 1.7 per cent change in cost of generation (TERI, 1987). Such considerations do enter into the analysis when a specific state like Gujarat is considered. Most of the studies indicate that substitution of fuel oil and naphtha in fertiliser plants yield a higher value added than for base load generation, replacing coal. Hence, if the market were to allocate the gas independent of external levies, replacement in the fertiliser industry is the most efficient.

Current economic price of natural gas

In the course of the study, an attempt was made to estimate the replacement value of natural gas at fertiliser plants and at power stations. For the fertiliser plants cost data for natural gas based plants was obtained from Projects and Development India, Limited (PDIL), NOIDA. Based on the capital investment estimates obtained from here, the capital costs given in the PDIL, Sindri (1985) report on the Economic Gradation for Consumers of Natural Gas, were inflated to 1991 prices. (As a cross check, inflation in the fertiliser industry at current prices was also calculated. Both were found to tally, i.e. 11 per cent).

Table 7 : Cost of Production of Fertilisers

	Natural gas	Naphtha	Fuel oil
Investment (Rs. crores)	509	548	512
Foreign Exchange Premium (Rs crores)	51	55	51
Cost (Rs. crores)	559	603	563
Annual capital cost/unit output (Rs./t)	10	11	15
O & M/unit output (Rs/t)	1883	3580	4231
Cost/unit (w/o fuel) (Rs/t)	1893	3591	4246
Fuel (Rs/t)			
natural gas	4024		
naphtha		6723	
fuel oil			8054
water	8	1	1
electricity	105	226	410
Total (Rs/t)	4137	6950	8465
Total Cost (w fuel) (Rs/t)	6030	10541	12711
Replacement value	-	9043	11213

The assumptions and data on which the above table is based are

a. costs of natural gas based plants were obtained from PDIL, NOIDA. Based on these estimates and those available in the PDIL, Sindri study, 1985, all figures in the study were appropriately inflated to arrive at current day (1991) prices. From the above method as well as from the price index (National Accounts Statistics) the average rate of inflation of fertilizer infrastructure/investments was found to be 11 per cent per annum.

b. On the same comparative basis mentioned above, O & M costs in the fertilizer industry were found to inflate at the rate of 19 per cent per annum.

c. The apportioning of O & M costs between ammonia and urea plants in naphtha and fuel oil base fertiliser plants was assumed to be in the same proportion as that in natural gas based plants.

d. Specific energy consumption in naphtha and fuel oil based plants was taken from the 1985 PDIL study. This, therefore, ignores any efficiency improvements in these two technologies over the years.

e. Efficient prices for natural gas and fuel oil were obtained from the TERI, 1991 study on Integrated Energy Pricing. Since the study had not included an estimate of the price of naphtha, export prices for the financial years were obtained from the Petroleum and Natural Gas Statistics, 1990-91. Based on the price index, this was extrapolated for the year 1990-91.

f. Transportation costs for coal and fuel oil were obtained from the RITES study, 1985. Using the inflation rate for the railways, the cost per unit transported was computed in current (1991) prices.

g. The capital costs for fertilizer units have been assumed to include capital servicing charges. h. A utilization rate of 90 per cent has been assumed for all fertilizer plants.

h. The imported component of the capital has been taken as 25 per cent, based on discussions at PDIL, NOIDA, and a premium of 40 per cent has been added, since the estimates pertain to the period prior to the decontrol of foreign exchange.

i. A 12 per cent discount rate has been assumed on the capital costs.

The analysis reveals that the highest replacement value of gas occurs with the replacement of fuel oil, followed by naphtha, in fertiliser production. This is consistent with the conclusions of most of the studies conducted so far.

An similar attempt to estimate the costs of generation in the power sector was carried out. The analysis does not include pollution control costs, except for electrostatic precipitators in coal based power plant since their installation is mandatory. Tables 8 and 9 summarise the main assumptions underlying the estimates (given in Table 10).

Table 8 : Power Plants Comparative components

	TPS	GT	CCP
Capacity (MW)	420	373	362
Units sent out (GWh)	2079	2079	2079
Auxiliary consumption(%)	0.1	0.05	0.02
Gross generation (GWh)	2311	2189	2122
Plant load factor (%)	0.628	0.735	0.735
Coal consumption (tpa)	1892440		
Fuel oil consumption (kl)	18484		
Gas consumption (mcm)		692	499
Economic life (years)	25	15	15
Interest (%)	0.12	0.12	0.12
Interest during construction (%)	0.07	0.07	0.07
CRF	0.1275	0.1468	0.1468
O & M costs	0.025	0.025	0.025

TPS - Thermal Power Station
GT - Gas Turbine
CCP - Combined Cycle Plant

Table 9 : Phasing of Investment (%)

Phasing of investment			
	TPS	GT	CCP
year 1	0.10	0.15	0.15
year 2	0.25	0.30	0.30
year 3	0.30	0.40	0.40
year 4	0.30	0.15	0.15
year 5	0.05		

Table 10 : Comparative Cost of Generation

	TPS	GT	CCP
Investment + interest during construction (Rs million)	16	245	249
Annual Capital Cost (Rs)	2063659	35980579	36543200
O & M (Rs)	404639	6126471	6222270
FUEL (Rs)			
coal charge	1.34e+09		
fuel oil charge	7.20e+07		
natural gas charge		1.04e+09	7.47e+08
fuel charge	1.42e+09	1.04e+09	7.47e+08
Total Cost (Rs)	1.42e+09	1.08e+09	7.90e+08
Cost/unit generated (Rs/kWh)	0.614	0.492	0.372

The underlying assumptions and data are as given below

a. It has been assumed that the gas turbine availability is 90 per cent (TERI, 1985, for GAIL), and the load factor is 81.7 per cent. This is assumed to hold for both the gas turbine as well as the combined cycle plant. The two were used to determine the utilisation factor (73.53 per cent).

b. The ratios of installed capacity of gas and steam turbines has been assumed to be 1:0.48

c. In computing the total installed capacity of the gas based plants a 9 per cent allowance for deterioration in operating conditions has been made.

d. Auxiliary consumption for the plants has been considered as follows 2 per cent for the CCP, 5 per cent for the open cycle plant, and 10 per cent for the TPS.

e. Efficiencies of the three units have been assumed at 43 per cent for the CCP, 32 per cent for the open cycle and 30 per cent for the TPS.

f. Calorific value of the fuels have been taken to be 8500 kcals/cu.m for gas and 3500 kcals/kg for coal.

g. Capital costs were obtained from NTPC and were for the latest projects. All costs have been converted to 1991 prices using a 10 per cent rate of inflation. For gas projects, the investment in a spur line 20 kms long has also been included. Interest during construction was taken to be 7 per cent per annum.

h. Disbursement profiles for the three schemes have been obtained from CEA and a 7 per cent interest rate during this period has been assumed.

i. The imported components of the three plants have been obtained from NTPC and were 66 per cent for a TPS, 50 per cent for an open cycle plant and 55 per cent for a CCP. A 40 per cent premium has been added to this portion of the investment.

j. Economic price of gas and coal were obtained from the pricing study (TERI, 1991). The price of gas at landfall point was used while for coal pithead values were taken. Transportation costs from the RITES study,1985 were brought to 1991 prices using an inflation rate of 11 per cent for the railways (National Account Statistics, 1990-91)

k. Fuel consumption was determined on the basis of the efficiency of the system and the calorific value of the fuel.

l. Auxiliary consumption (of fuel oil) in a TPS was the norm given by NTPC.

m. Economic life was as mentioned by NTPC, i.e., 25 years for a TPS and 15 years for both the open cycle plant as well as the CCP.

n. A 12 per cent discount rate on capital costs has been assumed in determining the CRF.

o. O & M costs for all three systems was taken as 2.5 per cent of the capital investment.

The above analysis yielded per unit costs of generation in the three systems. With high efficiencies of operation and a high calorific value of the fuel, the generation costs for a CCP are the least. If pollution control costs were to be added, costs of coal based generation would increase more than the others, since the removal of additional pollutants of particulates and ash disposal would be necessary. All systems would require controls for oxides of sulphur (if the gas has not been sweetened prior to combustion) and nitrogen.

Based on the results arrived at above, the study attempted to determine the economic, efficient price of natural gas in the two sectors, substituting three fuels. The results are as tabulated below.

Table 11 : Economic Price of Gas

Use	Fuel replaced	Rs./1000 cu.m
Fertiliser	Naphtha	9256
Fertiliser	Fuel oil	11477
Power station (1072 km)	Coal	1114

The results indicate that the maximum price, in terms of replacement value, of natural gas is when it is substituted for fuel oil in the fertiliser industry. The second best is the substitution of naphtha in the same industry, followed by the replacement of coal at a power station located 1072 kms away. Hence, if the market were to allocate natural gas, the demands of the fertiliser industry would be met prior to that of the power sector (for base load generation).

Substitution in the domestic sector

Currently there exists a major debate as to whether natural gas should be used for electricity generation or industrial sector applications, given the acute domestic fuel shortage facing the country. The current domestic fuel mix reveals a major share of traditional fuels, commercial energy contributing less than 50 per cent of the consumption. The effort in the subsequent section is to highlight the issues in the use of natural gas in the domestic sector.

The C3/C4 portions of the enriched stream of natural gas are fractioned out for the production of LPG. The gas left is basically comprised of lean gas (C1 fraction), with some part of C2 and C3 fractions. Depending on demand, these fractions of C2 and C3 are important feedstock in the petrochemical industry. Hence, the fraction traditionally left behind for meeting thermal energy requirements of the industrial, power and domestic sectors is the C1 stream. This comprises 75 - 95 per cent of the volume of the gas. The calorific value of this stream, which is primarily composed of methane, is around 8500 kcals per cubic meter (cu.m).

If one were to assume that only two competing demand sectors existed - the industrial and domestic sectors - and the allocation of the lean gas between the two was to be based solely on the basis of the willingness-to-pay criteria, the industrial sector would pre-empt a majority of the supplies. Within the domestic sector itself, the issues are complex. Replacement values of natural gas would have to be considered for a number of substitution options, eg. firewood, kerosene, and LPG. Given that kerosene is highly subsidized, a replacement with natural gas would never be cost effective to the consumer, if only convenience and market prices were considered. Hence, the argument on gas use in the domestic sector centres on the direct use through a distribution network thereby releasing LPG for use in other regions or expansion of existing LPG distribution facilities and piping the gas to areas not currently under the LPG distribution system. If convenience and ecological/environmental considerations are added, the viability of LPG or natural gas might be proved.

Natural gas can be directly used in the domestic sector, through a distribution network. Such a facility would involve a substantial investment in the supply network and would be limited to areas near gas reserves (in the case of off-shore gas, to the landfall point). On a comparative basis, the distribution of the same quantity of gas to industries would be substantially cheaper, given the tendency of industries locate at a nodal point. In the domestic sector, given the interests and political compulsions of various groups in the economy and the consumer education required, city gas distribution networks appear to be the most likely, thereby resulting in the replacement of LPG. A counter argument put forth is that such a distribution network would release LPG stocks currently being used to meet the city's demand for distribution in areas short of LPG (in most cases smaller urban centres). In this case what has to be considered is the desirability of replacing the existing LPG bottling and distribution network with a new infrastructure for piping the gas to houses. However, the replacement would occur between equally efficient fuels, varying only in terms of locational availability. The extension of facilities that are both more efficient and ecologically friendly to areas that are currently deprived of access to these fuels might serve the cause of promoting social justice as well as reducing harmful environmental consequences of deforestation.

The section has reviewed past studies and has attempted to estimate the economic price of natural gas for various end uses. If the choice of using natural gas was solely between the fertiliser and power sectors and the market effected the distribution, the need of the fertiliser sector would be met first. However, despite not quantifying the replacement value of gas in the domestic sector, the demands of this sector cannot be ignored. Further study/analysis for the same would be required.

PART II

This section deals with the current reserves and demand/supply scenarios in the country. As of 1991, the proven and indicated balance recoverable resources of natural gas were 730 billion cu.m. (bcm). These reserves are located mainly along the west coast between the Gulf of Cambay and Bombay and in the NE region of Upper Assam. This can be broadly disaggregated as (i) Bombay high offshore basin (484 bcm), (ii) Cambay Basin (93 bcm), (iii) Upper Assam (includes reserves in Tripura, Nagaland, Tamil Nadu, Arunachal Pradesh and Andhra Pradesh) (152 bcm), and (iv) Rajasthan (1.22 bcm). A part of the natural gas occurs as associated gas, the production of which is related to fuel oil production.

National gas consumption is still extremely low with well over 40 per cent of the gas produced being flared. Industry accounts for approximately 98 per cent of gas consumed, largely in the fertilizers and petrochemicals industries (non-energy) and for power generation.

A break up of gross production in 1990-91 shows onshore production at 3916 million cubic metres (mcm), with upper Assam accounting for 2011 mcm, Tripura and Tamil Nadu for 180 mcm and Gujarat 1696 mcm. Most of the production was from the offshore source of Bombay High, i.e., 14082 mcm. Gross and net production can further be stated in the following:

Table 12: Gross and Net Production of Natural Gas@ (million cubic metres)

	Gross Production	Re-injected	Flared	Net Production
Gujarat	1696	-	402	2194
Assam	2220*	102	681	1437
Bombay High	14082	-	4047	10035
Total	17998	102	5130	12766

* includes Tripura/Tamil Nadu & Andhra Pradesh
@ Provisional estimates

Industry wise offtakes of natural gas reveal that about 74 per cent is consumed for power generation and in the fertilizer industry. The trend can be seen from Table 13.

Table 13 : Industry-wise off takes of Natural Gas Energy Purpose (million cubic metres)

	Power Generation	Industrial fuel	Tea plantation	Domestic fuel	Captive use/LPG shrinkage	Total
1970-71	261	116	15	-	68	460
1974-75	354	164	29	6	80	633
1980-81	492	163	45	14	176	890
1984-85	1454	250	62	18	721	2505
1990-91*	2211	1178	71	47	1178	5285

Table 13 : (cont.) Non-energy purpose

	Fertilisers	Petro chemicals	Others	Total	Grand Total
1970-71	187	-	-.	187	647
1974-75	318	-	-	318	951
1980-81	611	5	16	632	1522
1984-85	1603	10	23	1636	4141
1990-91*	7345	38	98	7481	12766

* Provisional

While the trends have been as mentioned above, the Varadarajan report recommended that preference be given for the supply of gas to the power sector. This has been suggested, given that the option to import fertilizers exists and is simultaneously a less expensive alternative. Further, since capital costs of gas based power plants are lower and gestation periods shorter than for coal based plants, gas generation has been encouraged in the VIII Plan. The report also mentions that for gas to be provided for base load generation, the power station should necessarily be far way from pitheads and use associated gas. Free gas, given the greater control possible, should be used for peaking purposes.

Future demand scenarios

In order to estimate future gas demand scenarios, an attempt has been made to provide snapshot pictures of future energy demands, based on past growth and patterns and energy demand. Sectoral growth patterns have been were estimated and useful energy norms applied; the useful energy norms being distributed over various fuel alternatives accounting for efficiencies of utilization, availability of fuel types and present distribution patterns. Future scenarios are computed on the basis of a GDP growth rate of 5 per cent per annum and a population growth of 2.01 per cent per annum till 1999-2000 and 1.81 per cent per annum thereafter.

In all subsequent sections the focus will be on the southern and western regions, given that the principle aim here is to determine the viability of gas based power stations in these regions.

Electricity

Past trends reveal that electricity demand over the last two decades has grown at an annual average rate of 8 per cent and that of coal and oil at 5.6 & 5.8 per cent respectively. Based on the above assumptions, the growth in electricity demand over the next 20 years is expected to be around 6 per cent. This could be a result of factors like conservation, more efficient use (of energy) in agriculture, technology/process change in industry, etc. However, natural gas consumption increases at nearly 9 per cent annually.

Demand projections for electricity, disaggregated to the regional level reveal that demand in industry grew the most rapidly followed by that of the domestic and transport sectors. Projections till the year 2009-10 are given the tables below:

Table 14 : Demand projections for electricity (GWh)

1989-90	Western	Southern	All India
Industry	32873	25077	90604
Transport	1055	1015	4933
Domestic	11060	7821	33840
Agriculture	7484	9414	45302
Others	5830	4814	19409
Total	58302	48140	194088

Table 15 : Demand projections for electricity (GWh)

1994-95	Western	Southern	All India
Industry	47807	36137	128130
Transport	1320	1209	6078
Domestic	13849	11259	47375
Agriculture	18802	16400	92175
Others	9086	7223	-
Total	90863	72228	

Table 16 : Demand projections for electricity (GWh)

1999-2000	Western	Southern	All India
Industry	65622	51393	175365
Transport	1435	1310	6801
Domestic	15896	13955	58818
Agriculture	21464	19143	105211
Others	11602	9523	38466
Total	116019	95233	384661

Table 17 : Demand projections for electricity (GWh)

2004-2005	Western	Southern	All India
Industry	93370	72712	247748
Transport	1998	1752	9421
Domestic	18106	17287	73445
Agriculture	24540	22365	120389
Others	15335	12680	50111
Total	153349	12696	501113

Table 18 : Demand projections for electricity (GWh)

2009-2010	Western	Southern	All India
Industry	134712	106791	359369
Transport	2772	2337	12998
Domestic	22743	21657	94946
Agriculture	28095	26157	138021
Others	20925	17438	67259
Total	209247	174379	672593

In terms of percentage shares, the electricity consumption in the industrial sector is expected to increase from the present level of approximately 47 per cent to over 53 per cent in 2009-10. Shares of both domestic and agricultural sectors are expected to decline to 14 & 21 per cent from 17.5 and 23 per cent, respectively. The all India peak demand is estimated to increase from 42000 MW in 1989-90 to 115000 MW in 2009-10. The lower rate of growth of peak power as compared to that of electricity will probably be due to the increasing share of the industrial sector which has a relatively smoother load profile vis-a-vis the domestic sector.

Fuel demand

Looking at primary fuel source (coal, oil and gas) requirements to meet power demand in the two regions over the next 20 years, one finds that demand for the three fuels increase substantially.

Table 19 : Demand Projections for Coal (MT)

Year	Western	Southern	All India
1989-90	40	20	115
1994-95	59	29	169
1999-2000	74	40	222
2004-05	90	56	287
2009-10	115	80	389

The share of the power sector in total coal consumption is expected to increase from about 57 per cent to 60 per cent. This will be at the expense of the industrial sector. The percentage share of the western region in total coal consumption is expected to decrease, while that of the southern (and northern) regions increase.

Table 20 : Demand Projections for Oil ('000 t)

Year	Western	Southern	All India
1989-90	451	912	2609
1994-95	655	1327	3794
1999-2000	907	1667	4998
2004-05	1253	2023	6451
2009-10	1802	2587	8759

The share of both the western and southern regions in total oil consumption increase marginally in the period 1994-95 but remain constant thereafter. Overall, the share of power (in total oil consumption) is expected to remain constant i.e., around 5 per cent. Demand projections for natural gas are as indicated in Table 21.

Table 21 : Demand Projections for Natural Gas (mcm)

	Western	Southern	All India
1989-90			
Industry	2942	942	5870
Power	1230	353	3380
Total	4172	1295	9250
1994-95			
Industry	3237	1037	6458
Power	6138	1760	16869
Total	9375	2796	23327
1999-2000			
Industry	5308	2003	10779
Power	9774	2702	25969
Total	15083	4704	36748
2004-05			
Industry	7874	2996	15929
Power	11547	3273	30875
Total	19421	6269	46804
2009-10			
Industry	11959	4624	23924
Power	14366	4181	38673
Total	26325	8805	62597

The table indicates a likely increase in natural gas consumption at the rate of 9 per cent per annum over the period 1989-90 to 2009-10. The power sector would account for close to 62 per cent of this demand; the rest by industry. The shares of the western and southern regions in total consumption are expected to increase.

Overall a change in the fuel mix is expected, with the south increasing its share of both coal and gas consumption (and electricity as well), and the west reducing its dependence on coal by increasing the use of gas.

Energy supply

Supplies of major fuels have been considered. Traditionally supplies of most major conventional, commercial energy sources have been constrained by the non-availability of capital resources. Energy supply scenarios till the year 2010 have been constructed, keeping in mind the resource constraints and consistent with energy demand projections. This has been done by extrapolating the relationship between GDP and actual/planned investment in the energy supply subsectors.

Based on the above, the comparative availability of the three major fuel forms has been considered.

Table 22 : Estimates of Projected Coal Production (MT)

UG/OC	CC/NCC	1989-90	1994-95	1999-2000	2004-05	2009-10
Western	Total	75.2	86.7	99.2	114.0	125.9
OC	CC	0.9	1.2	1.5	1.8	2.0
OC	NCC	54.1	70.9	88.4	106.9	120.61
UG	CC	2.5	1.8	1.2	0.7	0.4
UG	NCC	17.6	12.8	8.1	4.7	2.9
Southern	Total	17.8	36.8	42.4	47.3	47.8
OC	CC	-	-	-	-	-
OC	NCC	7.5	23.4	29.4	36.0	37.5
UG	CC	-	-	-	-	-
UG	NCC	10.3	13.4	12.9	11.4	10.3

UG: underground
OC: opencast
CC: coking coal
NCC: non coking coal

All India production of coal has been divided over regions on the basis of the percentage share of total coal reserves in each region. The distribution of coking and non-coking coal is assumed in a similar fashion. Total coking coal production is projected at over 141 Mt by 2009-10, a major portion of which would be of poor quality, most suitable for use in industrial/utility boilers as fuel.

Lignite production, as a percentage of total coal production, is assumed to remain the same, i.e. 5.7 per cent. Given that major reserves are in Tamil Nadu, production for the southern region is maximum.

Table 23 : Estimates of Projected Lignite Production (MT)

Region	1989-90	1994-95	1999-2000	2004-05	2009-10
Western	1.1	1.9	2.0	2.1	2.2
Southern	10.5	14.8	20.0	26.4	34.5

So far, only about 25 per cent of the prognosticated hydrocarbon reserves have been proven. Certain indices with regard to basins in the southern and western regions are provided below.

Table 24 : Hydrocarbons - Basin Particulars

	Prognosticated reserves (mtoe)	Reserve /Production ratio	Expected discovery index (t/m)	Total Development drilling cost (Rs/m)	Gas oil ratio (cm/t)
Onshore	7772				
Western Region					
Cambay	1650	10	188	10917	249.9
K. Saurashtra	263	15	257	10917	835.1
Southern					
K.Godavary	217	15	286	16702.2	2796.5
Cauvery	166	15	273	10917	835.1
Offshore	12773				
Western Region					
K. Saurashtra	497	15	832	46324.8	436.9
Bombay High	7390	15	701	39258	455.8
Southern					
K.Godavary	543	15	1374	46324.8	549.8
Cauvery	374	15	643	43183.8	829.1
Kerala Konkan	1630	15	696	39259.8	2919.2

Projections of associated gas production indicate an annual average growth rate of 7.24 per cent; the potential increasing from 18.10 bcm to 53.13 bcm in 2009-10.

Table 25 : Projections of Associated Gas Production (bcm)

	1989-90	1994-95	1999-2000	2004-05	2009-10
Onshore					
Western Region					
Cambay		1.652	1.767	1.889	2.020
K. Saurashtra		0	0.001	0.002	0.051
Total		1.652	1.768	1.891	2.070
Southern					
K.Godavary		0.008	0.049	0.283	1.653
Cauvery		0.209	0.315	0.475	0.715
Total		0.218	0.364	0.758	2.368
Offshore					
Western Region					
K. Saurashtra		0	0.001	0.005	0.265
Bombay High		14.996	18.528	22.892	28.285
Total		14.996	18.529	22.897	28.550
Southern					
K.Godavary		0.212	0.452	0.963	2.052
Cauvery		0	0.006	0.106	1.882
Kerala Konkan		0	0	0.006	1.046
Total		0.212	0.458	1.076	4.979
TOTAL					
Western		16.648	20.297	24.788	30.62
Southern		0.43	0.822	1.834	7.348

The power supply industry in India is one of the fastest growing subsectors. It is estimated that about 25150 MW of new capacity will be added between April 1990 and March 1995, 29750 from April 1995 to March 2000, 34480 MW from April 2000 to March 2005 and 51770 MW between April 2005 & March 2010. The gross and net generation in the western & southern regions are as detailed below:

Table 26 : Projections for Gross & Net Generation (GWh)

	1994-95	1999-2000	2004-05	2009-10
Gross generation				
Western				
Coal	90719	113994	138298	176924
GT/CCP	21805	34720	41020	51030
Southern				
Coal	44801	62049	85667	123201
GT/CCP	6251	9597	11627	14854
Net generation				
Western				
Coal	81647	102594	124468	1592328
GT/CCP	21260	33852	39995	49754
Southern				
Coal	40321	55844	77100	110881
GT/CCP	6095	9357	11336	14483

The table has been constructed from projections of capacity addition on the basis of the following assumptions (a) for coal fired plants, gross generation is 4900 kWh/kW installed capacity and 10 per cent of gross generation, (b) for gas fired plants, gross generation is 7000 kWh/kW and auxiliary consumption 2.5 per cent of gross generation, (c) specific consumption of coal is 0.65 kg/kWh and gas 0.2815 cum/kWh, (d) efficiency of a TPS is 30 per cent and a CCP 43 per cent.

Table 27 : Coal Shortage (MT/y)

	1994-95	1999-2000	2004-05	2009-10
NCC				
Western	15.6	25	39.2	69.1
Southern	12.6	22.7	35.4	67.2

Table 28 : Demand Shortfall of Gas (bcm)

	1994-95	1999-2000	2004-05	2009-10
Western	-	-	-	-
Southern	2.366	3.882	4.435	1.458

It is assumed that these shortfalls will be compensated by the increased production of free gas, thereby equating production to demand, keeping flaring negligible.

Table 29 : Power Shortage (%)

	1994-95	1999-2000	2004-05	2009-10
Western	1.02	0.32	7.19	12.33
Southern	20.17	19.78	22.16	22.45

Table 30 : Peak Shortage (%)

	1994-95	1999-2000	2004-05	2009-10
Western	10.45	9.76	14.44	17.61
Southern	7.91	10.36	16.01	18.38

The section gives an indication of the extent of reserves, though not abundant ones, in the country. Currently considerable speculation with regard to the estimation of reserves has been raised; the most contemporary thought being that the reserves have been overestimated. Hence, the previous expansion plans in terms of setting up gas based capacity are undergoing serious rethinking. The discussion above also suggests major shortages of power and peak load. Shortfalls in the supply of coal are also envisaged. There appears to be a shortfall in the availability of gas in the southern region to meet current planned expansion activities. Given this backdrop and that additional hydrobased power is unlikely, given interstate disputes, ecological problems long gestation periods and monsoon failure/lack of assured supply of water, the utilisation of gas for peaking purposes could be suggested as an initial step. Once a clearer picture on the reserves is known, the desirability of expanding gas utilisation networks can be investigated. The increased use of gas in the western region, however, can be suggested.

PART III

The preceding sections have individually highlighted on the viability of combined cycle plants vis-a-vis conventional coal plants and the current reserves of fossil fuels in India. Further, the forecasted trends in demand of electricity have been mentioned in order to focus on the expected CO_2 emissions in the coming years. While the viability of CCP is proven beyond doubt, its widespread application in India is suspect, given the limited reserves of gas and the current speculation surrounding the estimates of the reserves. The paper is not an attempt to prove or to suggest the retrofitting of all conventional coal plants in the Southern and Western regions of the country. Given the large reserves of coal in the proven category, it is unfeasible for such a widespread substitution to take place. However, there are certain regions such as Gujarat that are far from sources of coal but close to substantial gas reserves. For such regions the changeover to gas based generation might prove to be a cheaper alternative. However, were the changeover to be viewed purely from an environmental point of view, the suggestion would be to replace all coal based plants by gas based generation. (This would suggest that neither reserves nor capital are constraints, both of which are untrue for a country like India, but this aspect has been excluded from the analysis for the present). The replacement of a fuel with a high carbon value by a fuel with a lower value is environmentally more benign in terms of reduced CO_2 emissions. This sections, thus, attempts to estimate the costs associated with reducing CO_2 emissions.

Table 31 gives an estimate of the electricity requirements in the western and southern regions till the year 2010.

Table 31 : Projections of Gross Generation (GWh)

	Apl'90-	Apl'95-	Apl 2000-	Apl'05-
	March 1995	March 2000	March 2005	March 2010
Western Region				
Coal	90718.6	113993.6	138297.6	176924
GT/CCP	21805	34720	41020	51030
Total	112523.6	148713.6	179317.6	227954
Southern Region				
Coal	44800.7	62048.7	85666.7	123200.7
GT/CCP	6251	9597	11627	14854
Total	51051.7	71645.7	97293.7	138054.7

Given the above generation mix, the estimates of fuel consumption are arrived at on the basis of the following specific consumption norms coal consumption - 0.65 kg/kWh and gas consumption - 0.2815 cm/kWh (this is weighted average of the specific consumption in an open cycle and combined cycle plant in the ratio of 65:35). Table 32 gives the fuel requirements for the business-as-usual (BAU) scenario, while Table 33 gives fuel requirements for the case where only gas is used for power generation.

Table 32 : Fuel Requirements for BAU Scenario

	Apl'90	Apl'95	Apl 2000	Apl'05
	March 1995	March 2000	March 2005	March 2010
Western Region				
Coal (Mt)	59	74	90	115
GT/CCP (mcm)	6138	9774	11547	14365
Southern Region				
Coal (Mt)	29	40	56	80
GT/CCP (mcm)	1760	2702	3273	4181

Table 33 : Requirements of gas

	Apl'90	Apl'95	Apl 2000	Apl'05
	March 1995	March 2000	March 2005	March 2010
Western Region				
gas (mcm)	31675	41863	50478	64169
Southern Region				
gas (mcm)	14371	20168	27388	38862

The fuel mix outlined in Table 32 and 33 yield CO_2 emissions as mentioned in Tables 34 and 3

Table 34 : CO_2 Emissions from BAU Strategy (Mt)

	Apl'90	Apl'95	Apl 2000	Apl'05
	March 1995	March 2000	March 2005	March 2010
Western Region	-			
Coal	126.19	158.57	192.38	246.11
GT/CCP	21.62	28.21	31.43	36.54
Total	148	187	224	283
Southern Region				
Coal-	62.32	86.31	119.17	171.38
GT/CCP	13.67	15.38	16.42	18.07
Total	76	102	136	189
Total	224	288	359	472

Table 35 : CO_2 Emissions from the Gas Option

(Mt)

	Apl'90	Apl'95	Apl 2000	Apl'05
	March 1995	March 2000	March 2005	March 2010
Western Region				
gas	67.94	86.42	102.05	126.89
Southern Region				
gas	36.55	47.07	60.17	80.98
Total	104	133	162	208

From Tables 34 and 35, the net reduction in CO_2 emissions consequent to the adoption of an all gas based generation policy are arrived at. These are given in Table 36 below.

Table 36 : Net Reduction in CO_2 Emissions (Mt)

	Apl'90	Apl'95	Apl 2000	Apl'05
	March 1995	March 2000	March 2005	March 2010
Western Region	79.87	100.36	121.76	155.76
Southern Region	39.44	54.63	75.42	108.47
Total	119.31	154.99	197.18	264.23

To arrive at the financial commitments for the two alternate strategies, costs derived in Part I of the paper have been used. The unit cost of generation from coal based plants is Rs 0.614/kWh and Rs 0.414/kWh for gas based plants (weighted average in the ratio of 35:65 for a GT and CCP).

Table 37 : Financial Requirements for Combined Strategy Rs. million)

	Apl'90	Apl'95	Apl 2000	Apl'05
	March 1995	March 2000	March 2005	March 2010
Western Region				
Coal	55723	70019	84948	108674
GT/CCP	9033	14383	16993	21140
Total	64756	84403	101941	129814
Southern Region				
Coal	27518	38113	52620	75675
GT/CCP	2590	3976	4817	6153
Total	30108	42088	57436	81828

In the case where only gas based generation capacity is installed, the investment requirements would be as given in Table 38.

Table 38 :Investment Requirements for Gas Strategy (Rs. million)

	April '90-March 1995	April '95-March 2000	April 2000-March 2005	April '05-March 2010
Western Region				
GT/CCP	46615	61607	74285	94433
Southern Region				
GT/CCP	21149	29680	40305	57191
Total	67763	91287	114590	151624

On the basis of the above, the cost per unit CO_2 abated works out to be Rs (-) 227.13864 /t CO_2 abated. This implies a net benefit from the switch over from coal based to gas based generation.

While the analysis does prove that switching from coal to gas is environmentally friendly and economic, for a country like India with limited reserves of natural gas, availability will have to be accorded due consideration prior to any investment decision/commitment being made.

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