THE ENERGY SECTOR

U. Sankar

with

G. Mythili

R. Anuradha

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2.1 Introduction

Until recently all enterprises in coal, petroleum and natural gas have been under central government ownership and control. In the electricity sector only 4.4 percent of the generating capacity was under private ownership. The central enterprises are engaged only in the generation of electricity. The SEBs are entrusted with the responsibility of generation (and purchase of power from central power stations), transmission and distribution of electricity in their respective regions.

Investment and pricing decisions of public enterprises have been under government control. The government has also used statutory public monopoly environment to achieve goals other than efficiency namely, equity and regional development. In the petroleum sector kerosene, diesel and liquified petroleum gas (LPG) for domestic use, and naptha for fertilizer use are cross-subsidised by gasoline, aviation turbine fuel and other products. In the power sector, domestic consumers and farmers are heavily subsidised. Most SEBs have been incurring huge financial losses. In the markets for electricity, kerosene and LPG, excess demands have been persisting for a long time. The government has been relying more on quantity controls in the form of quotas, power cuts, and waiting lists, than on the price mechanism to relieve the shortages. There is a growing concern that energy availability, particularly power availability may act as a binding constraint on India's economic growth. Even though nearly all these industries are publicly owned and their products are administered, the environmental costs of producing and using energy have not been included in the costing and pricing of the energy products.

Since June 1991, the government has announced various economic reforms under the stabilisation and structural adjustment programmes. These reforms have opened up the Indian economy to foreign competition, allowed private entry in areas hitherto reserved for the public sector and favoured market orientation in the management of public enterprises. The policy statements issued by the Ministry of Environment and Forests (MoEF) indicate the government's desire to use economic instruments for energy conservation and pollution prevention and control. Market-based instruments can provide signals to users of energy about the relative scarcity of resources and at the same time generate funds for further investments in these sectors.

The specific objectives of the study are to:

- review the supply and demand conditions, pricing policies, financial performances of the enterprises, and reforms initiated in the energy sector;

- assess the environmental damages in production and use of commercial energy, existing environmental regulations, environmental costs and policies for environmental protection;

- explore the feasibility of designing and implementing economic instruments for sustainable use of energy with focus on price reforms and carbon taxes, and assess their impact on energy consumption and improvement in the environmental quality; and

- recommend institutional, technological and other policies to ensure the successful implementation of the economic instruments.

This study is based primarily on published and unpublished data available from government agencies, public enterprises, research institutions, multilateral agencies such as the World Bank, United Nations Energy Programme (UNEP), World Resources Institute (WRI), Asian Development Bank (ADB) and journal articles. It makes use of available estimates of emission coefficients, input-output norms in energy industries, elasticities of demand and so forth.

Section 2.2 reviews the existing scenario related to production, consumption, pricing, financial performance, and the economic reforms initiated. Section 2.3 deals with environmental damages resulting from production and the use of fossil fuels and assesses the existing environmental regulations. Section 2.4 deals with the design and implementation of two economic instruments (i) efficient pricing, and (ii) carbon emission tax and assesses their impact on the environment.

2.2 Existing scenario and reforms initiated

The compound annual rate of growth in commercial energy consumption during 1953-54 and 1991-92 was 6.3 percent. The faster rate of growth of commercial energy, compared with the total energy growth rate of 3.2 percent, indicates a continuous shift from non-commercial to commercial energy owing to factors such as industrialisation, urbanisation, growth in income and change in tastes.

The commercial energy consumption per capita in 1970 was 113 kilogram of oil equivalent (kgoe) as compared with 1195 kgoe for the world and 7655 kgoe for the U.S.A. The per capita consumption in India amounted to 9.5 percent of the world per capita consumption and 1.15 percent of the per capita consumption in U.S.A. In 1991, the per capita consumption in India was 337 kgoe, while the corresponding figures for the world and U.S.A. were 1343 kgoe and 7681 kgoe respectively. Thus in 1991, the per capita consumption in India was 25 percent of the world average and 4.4 percent of the average for the U.S.A.

The energy intensity of the Indian economy, measured in million tonne (mt) ofoil equivalent (mtoe) per Rs 1 billion in constant prices, had increased from 4.76 in 1970-71 to 6.04 in 1993-94. Using the data for the period 1953-54 to 1993-94 the following multiple regression equation with logarithm of commercial energy in million tonne of coal replacement (mtcr) as the dependent variable (lny) and ln GDP in 1980-81 prices (lnX), ln of relative price of fuel (ln P), and time and (time)^2 as explanatory variables, was estimated by ordinary least squares.

$$\ln y = \underset{(2.7155)}{-4.4344} + \underset{(0.2395)}{0.8430} \ln X - \underset{(-0.0662)}{0.1321} \ln P + \underset{(0.0068)}{0.0424}\, T - \underset{(.0009)}{.00035} T^2$$

$$R^2 = .9963$$

The output and price elasticities are 0.843 and -0.132 respectively.

Coal

The estimate of coal reserves as on 31 March 1995 was 200 billion tonnes of which 68.6 million tonnes was proved. Coal production in 1994-95 was 254 mt, of which 17 percent was coking coal and 83 percent non-coking coal. The sulphur content of Indian coal varies between 0.3 and 0.8 percent, the average being 0.45 percent. The quality of non-coking coal is specified in terms of useful heat value (UHV):

$$\text{UHV (Kcal/kg)} = 8900 - 138\ (\%\ \text{ash} + \%\ \text{moisture})$$

The ash+moisture content of non-coking coal varies between 15 to 40 percent; correspondingly the UHV varies from over 6200 to less than 2000.

Coal consumption during 1993–94 was 253 mt of which coking coal was 12.8 percent. About two-thirds of non-coking coal is used by thermal power plants. The administered prices of coal varied from Rs 1048 for steel grade I to Rs 183 for grade G of non-coking coal. The overall return on capital employed was only 5 percent in 1990–91 but it improved to 11 percent in 1992–93.

The central government amended the *Coal Mines Act 1973* with effect from 9 June 1993 to allow private participation in mining for the purposes of power generation and for industrial uses. The government announced deregulation of prices of coking coal and grades A, B and C of non-coking coal in February 1996.

Petroleum and Natural Gas

As on 1 April, 1994, India's proven and balance recoverable crude oil reserve was 765 mt of which 310 mt came from on-shore fields and 455 mt from offshore fields. The estimate of proven balance recoverable reserves of natural gas on that date was 707 bm^3. In 1994–95 production of crude oil was 32.23 mt and imports 27.350 mt. The demand for petroleum products increased at the rate of 7.6 percent per annum during the Eighth Plan.

The prices of both domestic and imported crude oil are pooled in the crude oil prices equalisation account so that all refineries are supplied crude oil at a uniform price. The pricing mechanism for petroleum products is complex. The prices paid to refineries vary depending on their costs of production and various norms. The retention prices for distributing and marketing agencies are based on certain norms of operation.

At present prices of petroleum products such as gasoline, diesel, kerosene, LPG, Fuel Oil (FD), Low Sulphur Heavy Stock (LSHS), Naptha, Aviation Turbine Fuel etc. are administered. The central government fixes the ex-storage point prices for these products. These products account for about 90 percent of the total volume of petroleum products. For other products such as benzene, lube base oil and lubricants, the oil companies are free to fix the selling prices on market considerations.

There has been a steady increase in the price of petrol, but the price of High Speed Diesel (HSD) has been kept at a very low rate. The selling price of kerosene is being maintained far below the cost of supplying it, presumably to make it affordable to poorer sections of the population. The relatively low price of kerosene, compared with diesel, has also resulted in the adulteration of HSD with kerosene. The relatively low price of diesel compared with petrol has encouraged some automobile owners to retrofit the vehicles with diesel engines. Diesel oil, naptha and kerosene are cross-subsidised by petroleum, ATF and other products.

The petroleum sector contributes to central and state government revenues in the form of cess, royalty and gas. The eight public enterprises earned an overall rate of return of 17 percent on capital employed in 1992-93.

The new policy permits private entry in the exploration of oil and gas, refining and marketing of selected petroleum products. It has permitted a parallel marketing system since February 1993 to market some petroleum products which face persistent excess demands as for example, kerosene, LPG and LSHS. Supply of unleaded petrol was started in the four metropolitan cities from 1 April, 1995. The government is considering a phased dismantling of the administered price mechanism.

Power

Of the 86,868 mw of generating capacity at the end of 1993–94, the share of utilities was 88.3 percent. The shares of hydro, thermal and nuclear power in the total capacity of utilities were 25.7 percent, 71.6 percent and 2.7 percent respectively. Of the total power generated by utilities in 1994–95, 23.5 percent was from hydel, 74.9 percent from thermal and 1.6 percent from nuclear plants. Compared with the international standard of 77 percent plant load factor for thermal power plants, the overall plant factor in India was only 60 percent; the figures for central, SEB and private sector plants were 69.2 percent, 55.00 percent and 65.9 percent respectively. The transmission and distribution loss as a percentage of electricity generated was 21.5 percent in 1993–94, about twice the international norm.

The share of industry in electricity consumption had fallen from 67.6 domestic in 1970–71 to 39.7 percent in 1993–94, but the share of agriculture had increased from 10.2 percent to 29.7 percent and that of domestic consumption from 8.8 percent to 18.1percent. During 1993–94, the peak shortage was 16.5 percent and the energy shortage was 7 percent.

The electricity tariffs of SEBs are administered by their respective state governments. Multipart tariff is ubiquitous in India. Users have to bear the initial costs of connection. The bimonthly tariffs for large users namely, industry, commerce, railway traction consist of demand charge and energy charge. No state has introduced time-of-day pricing. For households and LT industries there is only a combined (demand and energy) charge per kwh. Many states now adopt the inverted pricing formula. For agricultural use, many states charge on the basis of horsepower of pumpsets used for large farmers and provide free electricity to small and marginal farmers. Hence the marginal price per kwh for both classes of farmers is zero.

For 1994–95, the weighted average price was Rs 1.30 per kwh while the average cost of providing power was Rs 1.62, thus leaving a shortfall of Rs 0.32 per kwh of power sold. The average price for agricultural users was only 13 percent of the average cost; for the domestic category, this percentage was 55.

In the power sector, the central sector power generating units have been earning reasonable rates of return on capital as they are involved only in power generation. The financial performances of the SEBs have been dismal. During 1994–95, the gross subsidy on account of sale of electricity to agriculture and domestic categories was estimated at Rs 133.1 billion. Rs 53.1 billion was the surplus generated by sale to other sectors. The estimated rate of return on capital employed was –13.5 percent. The estimated gross subsidy for 1995–96 was Rs 157.6 billion and the rate of return was –14.6 percent.

Since July 1991, the government has announced many reforms relating to the power sector. The reforms focus primarily on private power generation. Restructuring of SEBs has not yet begun. The government has announced programmes for generating more power from existing power plants, conservation of power, and generation of power from non-conventional energy sources.

2.3 Environmental damages and policies

Coal

As the overburden to the coal ratio is 4:1, production of 160 mt through open mining involves an overburden of 632 mt. The suspended particulate matter (SPM) levels in some coal mining areas have increased six times since independence. Coal mining also contributes to emissions of methane gas, CH_4.

Indian non-coking coal contains almost 30 percent to 40 percent of ash which is far higher than in many other countries. Of the total ash, about 20 percent is deposited in the form of bottom ash and the remaining 80 percent in fly ash. For a typical 210 megawatt unit plant, (coal with 30 percent ash) on an average, 2.69×10^5 tonnes of ash have been generated per year. As a result, the dust concentration in the flue gas in the absence of any control measure would be 37.5 gms/Newton meter (Nm^3).

In India, beneficiation of coking coal has been in practice for the last four decades. While beneficiation of non-coking coal has not taken place. A recent exercise carried out for three coal beneficiation plants planned at the coal mine sites of *Dipka*, *Kalinga* and *Piperwar* gives the cost estimates for reducing the ash content of coal from 40 percent to various levels of ash (Table 2.1).

It may be inferred from Table 2.1 that the marginal beneficiation cost is increasing at an increasing rate beyond the reduction of ash below 30 percent Coal beneficiation not only improves the gross calorific value and hence useful heat value of coal, but it also yields other benefits such as increased boiler efficiency, reduction in auxiliary energy consumption, decrease in maintenance cost and more importantly reduction in transportation cost from the mine site to power plant.

Standards for air pollutants

As coal cleaning for non-coking coal is yet to be undertaken, the stringent emission standards notified by the Central Polllution Control Board (CPCB) necessitate an alternative mechanism to control SPM.

Table 2.1
Cost of Beneficiation of Coal*

(Rs per Million Kcal)

Particulars	I. Dipka Mine				
	Ash content	Ash reduction to			
	38%	34%	32%	30%	25%
1.ROM (Run of mine) cost	74.53				
2.Beneficiated coal cost		95.38	102.84	116.73	151.92
3.Beneficiation cost (2-1)		20.85	28.31	42.20	77.39
4.GCV = Kcal/kg	4166	4397	4585	4773	5244
	II. Kalinga Mine				
	41%				
1.ROM (Run of mine) cost	81.12				
2.Beneficiated coal cost		112.69	116.71	127.96	171.97
3.Beneficiation cost (2-1)		31.57	35.59	46.84	90.85
4.GCV = Kcal/kg	3824	4337	4527	4715	5186
	III. Piperwar Mine				
	42%				
1.ROM (Run of mine) cost	63.92				
2.Beneficiated coal cost		79.89	80.11	80.74	100.56
3.Beneficiation cost (2-1)		15.97	16.19	16.82	36.64
4.GCV = Kcal/kg	3700	4410	4598	4786	5256

* Based on the study conducted by Central Mine Planning and Design Institute.

The standards for SPM are 150 mg/Nm^3 in protected areas and 350 mg/Nm^3 for boilers of a size less than 200 mw and 150 mg/Nm^3 for boilers of size 200 mw and above in other areas. The mechanical dust collectors used in older plants are being replaced by more efficient collectors namely, electrostatic precipitators (ESP). Almost all power plants constructed after the mid seventies in India have installed ESP. If ESP works with an efficiency of 99.6 percent (anything below 99 percent is not desirable) then SPM can be reduced up to 99 percent and the added cost as a percentage of generation cost works out to between 2 percent and 4 percent But this excludes the cost of disposal of ash collected in ESP. As the collection mechanism in its dry state is very expensive, fly ash in India is generally collected in a wet form or as slurry, and a large area is required for ash disposal. It is estimated that during 1995, 200 mt of coal consumption produced 75 mt of ash which requires 17700 hectares of land. This problem can be reduced by utilising large quantities of fly ash in the production of bricks and cement and in road making.

As the sulphur content, on an average, in Indian coal (with the exception of Assam coal) is low, Sulphur Dioxide (SO_2) emission is not a problem in India. However, it can reach significant levels owing to clustering of thermal power plants. A typical 210 mw plant with 0.5 percent of sulphur would produce, on an average, 3584 tonnes per year of SO_2 in the absence of any control measure. This corresponds to an emission level of 1.23 gm/m^3.

SO_2 reduction can be achieved by two different methods:

1. Use of tall stacks to increase atmospheric dispersion.
2. Flue gas desulphurisation.

In India, only the first method has been in vogue to control SO_2 emission. The standards prescribed by CPCB for SO_2 are 14 x (Sulphur Dioxide emission in kg/hr)$^{0.3}$ metres for boilers of sizes less than 200 mw, 220 metres for sizes between 200 mw and 500 mw, and 275 metres for size 500 mw or more.

Nitrous Oxide(NO_x) is formed from the nitrogen in the fuel (fuel NO_x) and from nitrogen in the combustion air (thermal NO_x). The formation of thermal NO_x is dependent on the combustion temperature and throughput time. By burning the fuel at a lower temperature and shortening the throughput time of the fuel, the formation of NO_x can be suppressed. By modifying the burner design, it is feasible to reduce the emissions by more than 50 percent Low NO_x burners are still in the development stage. The burner price will add about 5 percent to the generation cost.

Carbon monoxide (CO) and gaseous hydrocarbons are emitted by the combustion process owing to the incomplete combustion of coal. Incomplete combustion may result from low air fuel ratio. The quantities of these gases emitted are so low that they can be neglected. Also any modification that reduces CO generally increases NO_x emissions and vice versa.

There are no standards prescribed for CO_2. Mitra (1993) estimated emission of CO_2 from coal using industries for three years from 1986-87 to 1988-89. It may be noted that, of the total emission, power generation accounts for more than 50 percent followed by steel and cement.

Environment friendly coal combustion technologies

At present all the power generated from coal is based on the Pulverised Coal (PC) plant. The thermal efficiency of a PC plant is low and its emission rate is high. An interim report on *Evaluation of Clean Coal Technology* submitted to the CPCB by the Tata Energy Research Institute (TERI) in December 1994 evaluates four Integrated Gasification Combined Cycle (IGCC) technologies for adoption in India. IGCC is based on the principle of conversion of coal to fuel gas which is burnt in gas turbines to generate power. The hot exhaust gas produces steam in a heat recovery steam generator for generation through conventional steam turbines.

The TERI report notes the following special features which distinguish IGCC power plants from PC plants: (a) reduction in the gestation period for power generation, (b) co-production of power and chemicals, (c) cogeneration opportunities, (d) higher plant availability, (e) less cooling water consumption, and (f) lower emission levels of SPM, SO_x, NO_x and CO_2.

A feasibility study of IGCC technology undertaken by the Council of Scientific and Industrial Research (CSIR) and Bechtel under USAID considered four technologies: Shell, Texaco, KRW and the moving bed gasifiers. It compared the performances of IGCC and PC plants based on the following criteria - plant resource requirements, power outputs, heat rates and efficiencies. The capital required per kw net and costs of generation for the four IGCC plants and two PC plants are given in Table 2.2.

The TERI report concludes that IGCC can be an attractive power generation alternative for India in the future. Among the four IGCC technologies, it prefers the KRW gasifier or similar fluidised bed gasification processes. It also cautions that the gasifier has been proven only on a pilot scale. The moving bed gasifier is less efficient and more costly but it is commercially proven and tested for Indian coal. The Eighth- Five- Year- Plan has allotted funds to build IGCC demonstration plants with a view to demonstrate the commercialisation of technology.

Petroleum and natural gas

Crude oil production can lead to surface pollution and air pollution. Surface pollution results from test spills coming out of the oil wells. Air pollution is caused from the flares or from the emissions coming out of the installations. Flares and oil spills from the installations continue to remain a major concern. The percentage of natural gas flared to gas production has come down from 38.3 percent in 1985-86 to 10.3 percent in 1992-93 and there is a plan to bring it down to less than 4 percent.

Table 2.2
Capital Cost and Generation Costs for Different Technologies

Plant	Capital cost per kw net at 1989 prices Rs	Cost per kwh at 1989 prices Rs	
		5500 hr/year	6000 hr/year
IGCC plant			
Shell	36418	1.46	1.35
Texaco	41500	1.70	1.58
KRW	25292	1.04	0.97
Moving bed	26103	1.16	1.08
PC plant			
Without FGD	19084	0.87	0.81
With FGD	23276	1.02	0.96

Source. Results from CSIR and Bechtel (USAID) feasibility study quoted in "Evaluation of Clean Coal Technology", Interim Report submitted to CPCB, by Tata Energy Research Institute, Dec 1994.

Petroleum refining processes can result in the pollution of water, air and soil owing to their effluents and emissions. Effluent Treatment Plants (ETPs) consisting of physical, chemical and biological treatment sections have been set up in oil refineries. Other measures such as in-plant treatment of pollutant rich effluent streams, segregation of oily waste water and storm water, regular monitoring of treated effluent and receiving water body quality, use of recirculating water systems, extensive reuse of treated effluent are being practised for control of water pollution. All the seven refineries are complying with Minimal National Standards (MINAS) standards relating to quantity and quality.

As for solid waste management, oily sludge from tank bottoms and oil separators is treated in melting pits provided at refineries for recoveries of oil prior to its disposal as land-fill within the refinery premises. It appears that the existing facilities for desludging of the crude oil tankers are limited. Similarly the refineries have very limited capability for reusing the treated effluent. The refineries face problems in the disposal of biological sludge which is generated during the process because dumping sludge is not allowed and its use as a biofertilizer has not been fully established.

The environmental problems in drilling oil and gas and in petroleum, except for gas flaring and treatment and disposal of sludges in the refining process are thus under control. Public firms have an incentive to internalise most of these negative externalities as the prices of crude oil and petroleum productions are administered on the basis of their production costs and they have been operating in a monopoly environment. Even for the private refineries which are subject to strict environmental standards, the producers' prices are administered on the basis of their costs, assuring 12 percent rate of return on their networth.

Emissions from vehicles

India probably provides one of the worst scenarios in the world for emission of pollutants from vehicles. During the last five years, there has been a dramatic increase in the number of vehicles in the country. Table 2.3 shows the figures of different categories of vehicles in the years 1985 and 1991 and their expected increases in the year 2001. As can be seen from the table, there has been a marked increase in the number of two-wheelers in the country within a period of five years.

Table 2.3
Population Growth of Three Different Categories of Vehicles in India

(in million)

	1985	1991	2001
Two-wheelers	5.1	14.1	34.6
Cars, jeeps & taxis	1.5	2.9	4.0
Buses & trucks	1.0	1.8	3.5
Total	7.6	18.8	42.1

Source. CPCB (1984)

The effects of vehicular emissions on human health are well-known. Lead present in the gasoline, when inhaled, causes difficulties in blood circulation. Carbon monoxide (CO) is a highly toxic gas and it gets absorbed in the blood and reduces oxygen intake; NO_x and SO_x aggravate breathing problems and cause eye and throat irritation. People living in air-polluted zones get a persistent cough which remains incurable. Many get constant allergy problems. Suspended particulate matter, when inhaled constantly, probably causes cancer.

The contributions of two- and three-wheelers towards CO and HC are very high, whereas diesel vehicles generate a lot of NO_x and CO. The total emissions of the three pollutants have been estimated to be of the order of 3.4 mt per year in the country.

The CPCB made an assessment of vehicular pollution in major cities using the emission factors laid down by the World Health Organisation (WHO). The estimated emission is given in Table 2.4.

Table 2.4
Estimated Vehicular Emission Load (tonnes per day) in Metropolitan Cities, 1994

Name of the city	Parti-culates	Sulphur dioxide	Oxides of Nitrogen	Hydro Carbon	Carbon Mono-oxide	Total
Delhi	10.30	8.96	126.46	249.57	651.01	1046.30
Bombay	5.59	4.03	70.82	108.21	469.92	658.57
Bangalore	2.62	1.76	26.22	78.51	195.36	304.47
Calcutta	3.25	3.65	54.69	43.88	188.24	293.71
Ahmedabad	2.95	2.89	40.00	67.75	179.14	292.73
Pune	2.39	1.28	16.20	73.20	162.24	255.31
Madras	2.34	2.02	28.21	50.46	143.22	226.25
Hyderabad	1.94	1.56	16.84	56.33	126.17	202.84
Jaipur	1.18	1.25	15.29	20.99	51.28	89.99
Kanpur	1.06	1.08	13.37	22.24	48.42	86.17
Lucknow	1.14	0.95	9.68	22.50	49.22	83.49
Nagpur	0.55	0.41	5.10	16.32	34.99	57.37
Grand Total	35.31	29.84	422.88	809.96	2299.21	3597.20

Source. PARIVESH newsletter CPCB, 2 (1), June 1995

2.4 Economic instruments for environmental protection

The design and implementation of economic instruments which integrate economic and environmental aspects into decision-making in the energy sector are considered here. Efficient social pricing of energy in the Indian context can remove the existing distortions in the energy markets and provide signals to the users of energy about the relative social scarcities of different types of energy. A carbon emission tax based on the carbon emission factor for each fuel which can result not only in energy conservation but also improvement in environment quality must also be considered. Given the fiscal crunch the government is facing and the poor financial status of coal and power enterprises, a judicious application of the instruments can generate adequate revenues for further investments in the sectors.

Price reforms

Electricity prices

An attempt is made to estimate the long-run marginal social costs (LRMSCs) of electricity at the consumer end and to use them for designing electricity tariffs. This exercise adopts the methodology developed by Munasinghe (1979), Sankar (1992) and Sankar and Hema (1985, 1992). The data available from the TERI report on IGCC technology are used. For transmission and distribution (T & D) costs and operation (O & M) and maintenance costs of power plants, the data from the Tamil Nadu Electricity Board (TNEB) is relied upon. Being a normative costing exercise the accounting cost estimates are modified to allow for feasible cost savings owing to improvements in operational efficiency. The cost estimates are at 1994–95 prices.

The capital cost of a KRW plant is taken as Rs 40 million per mw. Assuming a commissioning period of four years, the expected life of the plant as thirty years and a cost of capital at 15 percent the annual cost of capital per KW per year is Rs 7605. Adding operation and maintenance costs of Rs 655 per KW per annum, the annual capital related cost per KW becomes Rs 8260.

For every 1 mw of generating capacity, the desired level of investment in T & D is estimated at Rs 30 million. Assuming a commissioning period of two years, the expected life of the equipment of twenty five years and a cost of capital at 0.15, the capital cost per KW per year is Rs 4989. This cost is distributed among Extra High Tension (EHT), High Tension (HT) and Low Tension (LT) in the ratios 2:1:7. Adding operating and maintenance cost at each voltage level, the capital related T & D costs per KW per annum are Rs 1133 at EHT end, Rs 648 at HT end and Rs 4542 at LT end.

Assuming a reduction in T & D loss from 22 percent to 17 percent, the percentages of peak capacities to generating capacity at EHT, HT and LT ends as 90, 76.5 and 40.9 respectively, and the cumulative loss factors at EHT, HT and LT ends as 1.0702, 1.1962 and 1.3960 respectively, the capacity related costs per KW per year are Rs 10187 at EHT level, Rs 12333 at HT level and Rs 27352 at LT level.

Capital costs at consumer ends

For obtaining the capital costs from the voltage ends to different consumer categories, three additional parameters are required. Following the World Bank studies undertaken for SEBs in India and our earlier work, information on the three parameters for seven categories of consumers is provided in Table 2.5. The monthly capital cost per KW for each category is given in the last column of the table. These figures are obtained by first multiplying

(SPD/SMD) and (SMD/AMD) ratios by the relevant voltage-end costs and then dividing the resulting figures by 12.

As reported in Section 2.3, the cost of coal washing (reducing ash content up to 30 percent) as Rs 0.13 kwh is assumed. The cost per tonne of coal is assumed to be Rs 600 at the pit head and Rs1200 for a plant situated 1000 km from the fuel source. The computation leading to social cost per kwh in given is Table 2.5.

Table 2.5
Customer Category Characteristics
and Capital Cost per KW for Consumer Categories

Category	SPD/SMD	SMD/AMD	Load factor	Capital cost per KW per month* Rs
EHT continuous process industries	.85	.90	.75	649
HT other industries	.80	.80	.60	658
HT others	.80	.75	.50	617
LT industry	.60	.80	.30	1094
LT agriculture	.80	.75	.30	1368
LT domestic	.80	.55	.30	1003
LT commercial	.80	.75	.40	1368

* 1 month = 730.5 hours
SPD/SMD = System peak demand by simultaneous maximum demand
SMD/AMD = Simultaneous maximum demand by aggregate maximum demand

The costs given under Case (b) are appropriate only when a power plant is near a coal mine; otherwise one has to take into account the cost of transporting power or coal. In India power transmission cost from pit head station ranges from Rs 0.12 per kwh for short hauls to Rs 0.90 for long hauls. Hence the estimates given under Case (a) of items B and C of Table 2.6 are used as a basis for inferences regarding subsidies and cross subsidies and for price reforms. These unit costs range from Rs 2.30 for HT continuous process industries to Rs 7.62 for LT agriculture.

Table 2.6 A
Social Cost of Energy: Energy Cost at the Generating End per kwh (Rs)

	Case (a)	Case (b)
Coal cost per tonne	1200	600
(a) Coal consumption at 0.72 kg/kwh	0.8640	0.4320
(b) Cost of cleaning coal	0.1300	0.1300
(c) Oil at 1.25 ml/ kwh at Rs 7 per litre	0.0088	0.0088
Total	1.0028	0.5708
Auxiliary consumption (5.5%)	of power generated	
Cost of energy per kwh	1.0612 under case (a)	
	0.6040 under case (b)	

Table 2.6 B
Social Cost of Energy: Energy Cost at Voltage End (Rs)

a. Cost of power at the generating end Rs 1.0612	b. Cost of power at Rs 0.6040
Cost at EHT end	
1.0612 x 1.046 = 1.1100	0.6040 x 1.046 = 0.6318
Cost at HT end	
1.0612 x 1.134 = 1.2034	0.6040 x 1.134 = 0.6849
Cost at LT end	
1.0612 x 1.297 = 1.3763	0.6040 x 1.297 = 0.7834

Table 2.6 C
Social Cost of Energy: Capital and Energy Costs per kwh for Consumer Categories (Rs)

Consumer Category	Capital cost per kwh	Social cost of energy per kwh		Total social cost per kwh	
		(a)	(b)	(a)	(b)
EHT continuous process industries	1.19	1.11	0.63	2.30	1.82
HT other industries	1.50	1.20	0.68	2.70	2.18
HT others	1.69	1.20	0.68	2.89	2.37
LT industry	4.99	1.38	0.78	6.37	5.77
LT agriculture	6.24	1.38	0.78	7.62	7.02
LT domestic	4.58	1.38	0.78	5.96	5.36
LT commercial	4.68	1.38	0.78	6.06	5.46

Table 2.7 gives ratios of the existing tariffs to LRMSC tariffs. All the ratios are less than 1. Estimates of subsidies, based on the differences between the LRMSCs and the existing prices are Rs 568 billion for agriculture, Rs 238 billion for domestic. Rs 187 billion for LT industry, Rs 62 billion for LT commercial and Rs 38 billion for HT industry.

Table 2.7
Electricity Sector: Economic and Market Prices for 1994–95

Consumer category (1)	Average tariff in India/kwh (Rs) (2)	Social cost per kwh (LRMSC) (Rs) (3)	Ratio (4) = (2) ÷ (3)
EHT continuous process industries	2.02	2.30	0.87
HT other industries	2.02	2.70	0.75
HT others	2.40	2.89	0.83
LT industry	2.40	6.37	0.38
LT agriculture	0.22	7.62	0.03
LT domestic	0.88	5.96	0.15
LT commercial	1.91	6.06	0.32

In view of the steep increase in the electricity prices, particularly for LT-end customers, the immediate switch to LRMSC based prices at consumer ends would be politically infeasible. What must also be taken into account are the inflationary implications of steep increase in the price of an intermediate good like electricity.

With private entry in power generation and greater reliance on captive power plants by large industrial and other users, there is a limit to the cross subsidisation of domestic and agricultural consumers by the large users. In a market driven situation, if the cost of getting power from a SEB exceeds the stand alone cost of power for a larger user, the latter has an exit option. The exit of large consumers is not desirable to a utility system.

Equity considerations are important, at the present stage of development, in the pricing of electricity to households in India. As per the 1991 census only 31.1 percent of rural households and 75.9 percent of urban households or 43.0 percent of all households have electricity connections. Also more than one-fifth of the population lives below the poverty line. Hence there is a need for subsidising electricity to small income households upto a prescribed level of consumption. The minimum price for electricity may be set equal to the short run marginal social cost of electricity. This would mean that the electricity price for households with consumption of 100 kwh or less should be increased from the present level of Rs 0.65/Rs 0.75 to Rs 1.38. The unit charge may be raised to cover 50 percent of LRMSC from 1999-2000. For other households, the unit charge may be raised to cover 50 percent of the cost immediately and 100 percent of the cost from 2001-2002.

An immediate increase is called for in the price of electricity for agricultural use. The average price per kwh for this category for the country as a whole is only Rs 0.217, which is far below the price of Rs 0.50 per kwh recommended at the meeting of the state power ministers in 1994. Every effort should be made to raise the price of electricity to cover at least the short-run marginal social cost within a year. As ground water is becoming an increasingly scarce resource, as the alternative cost of pumping water using diesel-based pumpsets or bullock labour is around Rs 5 per kwh, and as most of the farmers with pumpsets are the relatively better off sections of the rural population, there is a case for increasing the electricity price to cover its LRMSC in a phased manner during the next five years. For small farmers cultivating 2 hectares or less, the price may be raised to Rs 3.81 by 1999–2000 so that it will cover 50 percent of the LRMSC.

Development of small scale industries has been encouraged to achieve the goals of dispersed rural development and employment generation. As the cost of providing electricity at the LT end is about 130 percent higher than the cost at the HT end, a steep increase in the price would discourage the growth of these industries. Hence, the price may be raised immediately to cover half of the cost and raised to Rs 4.25 to cover two-thirds of the cost from 1999–2000. As for the LT commercial group, equity and other considerations are less important. However, to avoid immediate steep increase in the charge, the charge may be fixed at two-thirds of the cost immediately and at 100 percent of the cost from 1999–2000.

The time pattern of proposed tariff revisions is given in Table 2.8. By 2000–2001, the only subsidised categories would be small farmers, the LT industry and small income households.

Impact of proposed tariff revision on electricity demand

In order to forecast the effects of the proposed revision of electricity tariffs on the sectoral demands and aggregate demand for electricity, even within a partial equilibrium framework, estimates are required of the sectoral growth rates of outputs, growth rate of GDP, own-price elasticities of demand and output/income elasticities. In Appendix 1 of the earlier report the studies based on the works of other researchers as well as our own on the energy demand functions have been reviewed. Based on these studies and noting the nature of regulation and excess demand conditions in the markets certain parameter values for own price and output/income elasticities (Table 2.9) have been chosen for the exercise.

Table 2.8 A
Tariff Revisions for 1996-97 (at 1994-95 prices)

(Rs per kwh)

Consumer category	Long run marginal social costs			Tariff in 1996-97		
	Capital cost	Energy cost	Total	Capital cost	Energy cost	Total cost
EHT continuous processing industries	1.19	1.11	2.30	1.19	1.11	2.30
HT other industries	1.50	1.20	2.70	1.50	1.20	2.70
HT others	1.69	1.20	2.89	1.69	1.20	2.89
LT industry	4.99	1.38	6.37			3.19
LT agriculture						
small farmers	6.24	1.38	7.62			1.38
large farmers	6.24	1.38	7.62			3.81
LT domestic						
small consumers	4.58	1.38	5.96			1.38
others	4.58	1.38	5.96			2.98
LT commercial	4.68	1.38	6.06			4.04

The proposed tariffs for the five sectors for the selected years, 1996-97 (last year of Eighth-Five-Year-Plan), 1999-2000 (last year of this century) and 2001-02 (last year of Ninth-Five-Year-Plan) are given in Table 2.10. In analysing the price impact an additional assumption has been made that for any price up to Rs 3.00 per kwh, except in the industrial sector, quantities demanded will remain at the 1994-95 levels.

Table 2.8 B
Tariff Revisions for 1999-2000 and 2001-2002
(at 1994-95 prices)

(Rs)

Consumer category	Tariff in 1999-2000			Tariff in 2001-2002
	Capital cost	Energy cost	Total	Total
EHT continuous processing industries	1.19	1.11	2.30	2.30
HT other industries	1.50	1.20	2.70	2.70
HT others	1.69	1.20	2.89	2.89
LT industry	-	-	4.25	4.25
LT agriculture	-	-		
small farmers			3.81	3.81
large farmers			5.08	7.62
LT domestic	-	-		
small consumers			2.98	2.98
others			3.98	5.96
LT commercial	-	-	6.06	6.06

The forecasts of the growth rates of electricity demand for the five sectors, under different assumed values of the elasticities, for the three periods are given in Table 2.11. Even with the tariff revision the aggregate demand for electricity will increase at the rate of 6 percent per annum till 1996-97. This result is due to two factors: the low tariff in 1994-95 and xcess demand in the markets for electricity. With phased increases in the prices of electricity, the rate of growth of aggregate demand for electricity is expected to be at 4.5 percent till the end of the Ninth Plan, if the price elasticity is -0.2. If the price elasticity is -0.3, then the annual rate of growth in demand would be 3.75 percent till the end of the Ninth Plan. If electricity prices are frozen at 1994–95 prices, then its demand will grow at the rate of 6 percent per annum.

Table 2.9
Parameter Values Used in the Simulation Study of Electricity Demand

Sector	Sector growth rate	Own price elasticities	Output/ income elasticities
Domestic	6%	-0.05, -0.2, -0.3	1, 1.5
Industry	9%	-0.15, -0.5	1
Agriculture	2%	0	1
Commercial	7%	-0.2, -0.4	1
All sectors (GDP)	6%	-0.2, -0.3	1

Table 2.10
Proposed Tariff for Each Sector

(Rs per kwh)

Sector	Actual	Proposed tariff		
	1994–95	1996–97	1999–2000	2001–2002
Domestic	0.88	2.98	3.98	5.96
Industry	2.20	2.70	2.70	2.70
Agriculture	0.22	3.81	5.08	7.62
Commercial	1.91	4.04	6.06	6.06
All sectors	1.30	3.19	3.91	5.10

Table 2.11
Impact of the Proposed Price Reforms on Electricity Demand

Sector	Own price elasticity	Growth rate between 1994–95 and 1996–97 (%)	Growth rate between 1994–95 and 1999–2000 (%)	Growth rate between 1994–95 and 2001–2002 (%)
Domestic (a)	-0.05	12.36	32.19	45.43
	-0.20	12.36	27.29	30.63
	-0.30	12.36	24.02	20.76
Domestic (b)	-0.05	18.54	49.10	70.61
	-0.20	18.54	44.20	55.81
	-0.30	18.54	40.93	45.94
Industry	-0.15	15.40	50.45	79.39
	-0.50	7.45	42.50	71.44
Agriculture	0	4.04	10.41	14.87
Commercial	-0.20	7.56	19.86	40.18
	-0.40	0.62	-0.55	19.78
All sectors	(At 1994–95 prices)	12.36	33.82	50.36
	-0.20	12.36	27.76	36.36
	-0.30	12.36	24.72	29.36

Note. It is assumed that income/output elasticities are equal to unity except for domestic sector where (a) refers to unitary income elasticity and (b) refers to an income elasticity of 1.5.

Own price elasticity of demand is assumed to be zero upto the price of Rs 3 per kwh for the domestic and commercial sector and for all sectors.

Coal

Following Bhattacharyya (1995), the economic prices for different grades of coal are estimated for the year 1994-95. The fuel price index is used for this price adjustment. These results are reported in Table 2.12. The table reveals that the economic prices are higher than the pithead prices for grades A and F of non-coking coal and medium coking coal. Based on Bhattacharyya's method, the distribution of subsidy/tax by consumer categories for 1994-95 is estimated. These results are reported in Table 2.13. These results indicate that the average pithead price per tonne is Rs 52 above the average economic price.

Table 2.12
Coal Sector: Economic and Market Prices for 1994-95

(Rs /tonne)

Grade of coal (1)	Pit-head price (2)	Economic price (3)	Ratio (4) = (2)÷(3)
	Non-coking coal		
Grade A	645	666	0.97
Grade B	589	446	1.32
Grade C	516	426	1.21
Grade D	409	368	1.11
Grade E	325	235	1.38
Grade F	260	266	0.98
	Coking coal		
Primary coking coal	906	845	1.07
Medium coking coal	542	585	0.93

Primary coking coal includes coking coal of steel grades I, II and washing grade I. Medium coking coal refers to washing grades II, III and IV.

Table 2.13
Coal Sector: Distribution of Subsidy/tax by Major Consumers for 1994–95

Consumer	Consumption (mt)	Assumed distribution of coal by category (mt)					Subsidy/ tax in billion Rs
		PCC	MCC	S	M	I	
Power utilities	167.00	–	–	27.88	83.66	55.46	9.551
Steel plant & cokeries	34.50	34.50	–	–	–	–	2.104
Railways	2.20	–	0.73	1.47	–	–	0.058
Cement	13.10	4.67	8.43	–	–	–	-0.078
Fertilizer	4.00	4.00	–	–	–	–	0.244
Soft coke	3.00	–	3.00	–	–	–	-0.129
Brick kilns	25.00	–	–	–	–	25.00	1.050

PCC - Primary coking coal; MCC - Medium coking coal; S -Superior non-coking coal; M - Medium non-coking coal; I - Inferior non-coking coal.

For pricing purposes, PCC includes steel grades I, II and washery grade I; MCC includes other washery grades coal; S includes coal grades A and B; M includes coal grades C and D and I includes coal grades E and F. Simple averages of prices for different grades are used as the price of any category. Negative sign in the last column implies market price is less than the economic price.

For the coal sector as a whole, setting coal prices for different grades of coal equal to their respective long-run marginal social costs would not result in any significant increase in revenue. Price reforms will result in price increases for coking coal supplied to steel companies and washed non-coking coal supplied to thermal power plants and other users. In the short run, say two or three years, price increases of the order envisaged above will not lead to reductions in demand for the different types of coal.

Petroleum products

The economic prices reported by Bhattacharyya (1995) for 1991-92 to arrive at the prices for 1994-95 have been adjusted by using the import price index of petroleum products. Table 2.14 gives information relating to the economic prices of petroleum products at Bombay for 1994-95. It provides estimates of subsidies in the prices: 54 percent for kerosene, 24 percent for LPG and 1 percent for fuel oil. The retail price of gasoline is 215 percent higher than its economic price. The total subsidies amount to nearly Rs 36 billion for kerosene and Rs 7 billion for LPG.

Table 2.14
Petroleum Sector: Economic and Market Prices (at Bombay) for 1994-95

Product (1)	Retail prices with tax (Rs) (2)	Economic prices (Rs) (3)	Ratio (4)=(2)÷(3)
Gasoline/litre	19.30	6.13	3.15
HSD/litre	7.80	5.63	1.39
Kerosene/litre	2.60	5.71	0.46
Fuel oil*/litre	5.16	5.20	0.99
LPG**/cylinder	91.90	121.40	0.76

* No retail sale, ex-depot rates, exclusive of sales tax.
** One cylinder = 14.2 kg.

The government announced on 2 July, 1996 the following price revisions on petroleum products with effect from 3 July, 1996.

Product	Percentage increase in price
Kerosene for domestic use	0
Naptha (other than fertiliser use)	10
ATF	10
Petrol (Motor spirit)	25
All other products including kerosene for industrial use and naptha for fertiliser use	30

Table 2.15
Petroleum Sector: Distribution of Subsidy/Tax by Major Consumers for 1994-95

(Billion Rs)

Product	Power generation	Industry	House-hold	Others	Transport	Total
Gasoline	-	-	-	-	77.62	77.62
HSD	0.39	4.86	-	3.37	69.73	78.35
Kerosene	-	-	-35.67	-	-	-35.67
Fuel oil	2.06	14.71	-	1.59	1.25	19.61
LPG	-	-1.32	-5.62	-0.13	-	-7.07

The proposed price increases will reduce the deficit in the oil pool account to Rs 20 billion by the end of 1996-97. However, distortions in the price structure still remain. While the open market price of kerosene is Rs 8.10 per litre, the price in the public distribution system is only Rs 2.55. The large deviation between the diesel price and kerosene results in the adulteration of diesel and diversion of kerosene from domestic use to other uses. The gap between petrol and diesel price has widened. Naptha is sold at Rs 3723 per kl for fertiliser units but the same naptha is sold at a price of Rs 6076 for other uses. The price of furnace oil for fertiliser plants is Rs 2812 per kl but the price is Rs 4535 per kl for other uses.

The steep increases in some petroleum prices have received widespread criticisms from the political parties, the business community and the general public. The government was forced to reduce the increase in the price of diesel from 30 percent to 15 percent. There is ,however, still some pressure to reduce the increase in the price of LPG for domestic use.

What would be the effect of the price revision on the demand for petroleum products? There is no increase in the price of kerosene for domestic use. As its relative price has fallen, the demand for kerosene would increase at a rate faster than the rate of growth of household income (6 percent per annum) but the gasoline market is quantity constrained. Allocations of naptha and fuel oil to fertiliser plants are made by the government.

We analyse market responses only in the case of gasoline (motor spirit), diesel and ATF. The results are given in Table 2.16.

The percentage changes in the quantities demanded in the first year would be 1.39 for gasoline, 4.67 for diesel and 4.55 for ATF.

Table 2.16
Impact of Increase in Petroleum Prices on the Demand for Gasoline, Diesel and ATF

Product	Price increase (%)	Own price elasticity	Output elasticity	Growth rate in output (%)	Annual growth rate 1996-97 to 2001-02 (%)	
					With price revision	Without price revision
Gasoline	25	-0.118	0.628	7	3.99	4.49
Diesel	15	-0.068	0.813	7	5.49	5.65
ATF	10	-0.250	1.000	7	6.38	7.00

Proposal for a tax on carbon emissions

Use of fossil fuels in power generation, manufacturing and transportation have been the most important source of CO_2 emissions in India. Mitra (1992) estimates the CO_2 emissions from fossil fuels at 153 million tonnes in 1989-90. TERI (1994) estimates the emissions for the same year at 166 mt. More than two-thirds of the emissions occur from the use of coal. Even though the per capita CO_2 emission was only 0.2 million tonnes of carbon in India, it is expected that, in view of the growing dependence on non-coking coal for power generation and the anticipated high rate of industrial growth at about 9 percent per annum, the per capita emission rate may double before the end of the century. The effects of introducing carbon emission taxes on coal, crude oil and natural gas must be taken into account.

Coal

The distribution of coal use gradewise by sectors is not available. In India, about 72 percent of the non-coking coal was used for power generation in 1994–95. Almost four-fifths of the coal used in thermal power generation corresponds to coal with ash and moisture contents above 35 percent. The weighted average price of pithead coal including cess and royalty per tonne for the two grades was Rs 318 in 1994–95. The total consumption of coal by thermal power plants in that year was 167 mt. Using an emission factor of 1.46 CO_2 per tonne of coal given in the ADB Report, the total CO_2 emissions from the use of coal in power generation is estimated at 243.82 mt.

With an emission factor of 1.46 tonne of CO_2 per tonne of coal and a $5 tax rate per tonne of CO_2, the tax per tonne of coal becomes Rs 229 which means an increase in the price of coal by 72 percent. In this exercise it is assumed that the entire tax is passed on to the users of coal because the existing administered price scheme is cost based and there is excess demand in the market. The estimated total tax revenue at the 1994–95 level of coal use is Rs 38.243 billion. If the tax were set at $10 per tonne of CO_2, the carbon tax per tonne of coal becomes Rs 458 which would increase the price of coal by 144 percent. The expected tax revenue at the 1994–95 level of coal use would be Rs 76.486 billion.

The delivered price of coal to a thermal power plant, apart from the pithead price includes cess and royalty, freight, handling and other charges. If coal is transported for a distance of 1000 miles, then the landed cost per tonne of coal becomes Rs 1247. In this case the price will increase only by 18 percent when the tax rate is $5 and by 36 percent when the tax rate is $10. The cost of delivered coal to power plants situated away from coal mines will also increase because of the increase in the transportation cost resulting from imposition of tax on fossil fuels used in the transportation sector.

When both coking and non-coking coal are considered, the emission factor of 1.88 tonne of CO_2 per tonne of coal given in the ADB Report has been used. Coal consumption in 1994-95 was 268.5 mt. and hence the estimate of CO_2 emission for the year was 504.78 mt. The average price of coal including royalty and cess for 1994-95 was Rs 487. At the tax rate of $5 per tonne of CO_2, the pithead price of coal would increase by 61 percent. The anticipated revenue from this tax at the 1994-95 level of coal use is Rs 79.25 billion. If the tax rate is $10 per tonne of CO_2 (Rs 314), the average price of pithead coal would increase by 122 percent and the total tax revenue at the 1994-95 level of coal use would be Rs 158.5 billion.

Crude Oil

The total consumption of crude oil in 1994-95 was 56.44 mt. Assuming an emission factor of 2.64 tonnes of CO_2 per tonne of crude oil, the total CO_2 emissions from petroleum products was estimated at 149 mt. in 1994-95. A $5 tax per tonne of CO_2 emission implies a tax of Rs 414.48 per tonne of crude oil. Since the price of crude oil inclusive of cess and royalty was Rs 4071 per tonne, with the introduction of the tax, assuming entire shifting of tax, the price would increase by 10.2 percent. The expected revenue from the tax at 1994-95 level of consumption is Rs 23.393 billion. The price increase for a $10 tax is 20.4 percent. The expected revenue from the tax for 1994-95 would be Rs 46.786 billion.

Natural Gas

The total consumption of natural gas for 1994-95 was 19 bm^3. Using an emission factor of 1.9 per tonne of CO_2 per 1000 m^3 of gas, the estimated CO_2 emission from natural gas for 1994-95 was 36.1 mt. The price of natural gas inclusive of royalty and cess in 1994-95 was Rs 2235 per 1000 m^3. Hence with the imposition of the tax, the price of natural gas would increase by 13.35 percent. The expected tax revenue from the $5 tax is Rs 5.668 billion. The expected price increase for the $10 tax is 26.7 percent and the expected revenue is Rs 11.335 billion.

Table 2.17
Impact of Carbon Emission Tax on Fossil Fuel Prices and Tax Revenues

Fuel	Tax rate per tonne of CO_2	Rate of increase in price (in per cent)	Tax revenue at 1994-95 level of use (in billion Rs)
Coal	$5 or Rs 157	61.0*	79.250
	$10 or Rs 314	122.0*	158.500
Petroleum	$5 or Rs 157	10.2	23.393
	$10 or Rs 314	20.4	46.786
Natural gas	$5 or Rs 157	13.35	5.668
	$10 or Rs 314	26.70	11.335
All fuels	$5 or Rs 157		108.311
	$10 or Rs 314		216.621

* Pit-head price of coal. Average rate of increase in the retail prices would be about 30.5 percent and 61 percent.

The impact of introducing a carbon emission tax at the rate of $5 per tonne of CO_2 or $10 per tonne of CO_2 on the prices of the fossil fuels and on the expected tax revenues, at the 1994-95 levels of consumption of fossil fuels, is given in Table 2.17. The maximum impact of the tax will be on coal prices. If coal is transported for a distance of 1000 km the landed cost would increase only by about 15 percent. Among the three fuels, coal is a relatively abundant fuel in India. A carbon tax will alter the relative fuel prices in favour of petroleum and natural gas and thereby increase the pressure on imports of crude oil and natural gas. But the tax provides an incentive to improve the coal quality by coal washing and coal beneficiation. The government may introduce the tax at a rate of \$5 per tonne of CO_2 and use the revenue to finance programmes such as coal beneficiation, development of environment friendly technologies in the energy sector and to adopt energy conservation measures.

The effects of increase in the prices on the demand for different fossil fuels would depend on the own and cross price elasticities of demand, the output/income elasticities of demand and the extent of excess demands in different markets. In fact, we need a general equilibrium framework incorporating the regulatory features and the market conditions in order to analyse the full impact of the tax on the demands for different fossil fuels.

In our work we make rough estimates of changes in the demand for fossil fuels due to the imposition of a once-and-for all carbon emission tax of \$5 per tonne of CO_2 in 1995–96, within a partial equilibrium framework under some strong assumptions.

The assumptions underlying the calculations are given in Table 2.18.

Impact on the environment

Based on the information contained in Table 2.18 and further assuming that the CO_2 emissions from coal use are proportional to the quantity of coal consumed, one finds that from 1994–95 to 2001–02 CO_2 emissions from coal use would increase by 82.8 percent in the absence of the \$5/tonne carbon emission tax and by 76.70 percent with the carbon emission tax (Table 2.19). If all coal-based plants are required to use washed coal with an ash content of 30 percent by 2001–02, then the annual rate of CO_2 emissions can be reduced from 8 percent to about 6 percent.

Table 2.18
Effects of a Carbon Emission Tax of $5 per tonne of CO_2 in 1995–96 on Demand for Fossil Fuels

Fuel	Rate of increase in price in 1995–96 (in %)	Own price elasticity	Output elasticity	Annual rate of growth of output (in %)	Rate of increase in fuel demand	
					1994–95 to 1996–97	1994–95 to 2001–02
Coal	30.50*	-0.1	1	9	13.76 (7.32)	–
		-0.2	1	9	–	76.70 (8.13)
Petroleum	10.20	-0.1	1	7	13.47 (6.52)	59.56 (6.90)
		-0.2	1	7	12.45 (6.04)	58.54 (6.80)
Natural gas	13.35	-0.1	1	6	11.03 (5.37)	49.03 (5.87)
		-0.2	1	6	9.69 (4.73)	47.69 (5.73)

Note. Figures in parentheses give the annual rates of growth.
* Average increase in the delivered price.

The potential for reducing CO_2 emissions from coal-based power plants by restructuring electricity tariffs appears to be greater than by introducing the carbon emission tax. Using the results in Table 2.12 and assuming that CO_2 emissions are proportional to the power generated from coal-based power plant, we estimate the rates of increase in CO_2 emissions during the period 1994–95 to 2001–02

(a) under the 1994–95 tariff level and (b) under the proposed tariff. With the proposed price reforms, the rate of increase in CO_2 emission from 1994–95 to 2001–02 is 36 percent if the price elasticity of demand is -0.2, and the rate of increase is 29.3 percent over the same period if the price elasticity of demand is -0.3. In the absence of the price reforms, the rate of increase in the emissions would be about 50 percent.

Table 2.19
Effects of a Carbon Emission Tax at the Rate of $5 per Tonne of CO_2 in 1994–95 on the Fossil Fuels on CO_2 Emissions in 2001–02

Fuel	Own price elasticity	Rate of increase from 1994–95 to 2001–02 (%)	
		With the carbon tax	Without the carbon tax
1. Coal	-0.1 till 96–97 and -0.2 thereafter	76.70	82.80
2. Petroleum	-0.1	59.56	60.58
	-0.2	58.54	60.58
3. Natural gas	-0.1	49.03	50.36
	-0.2	47.69	50.36

The volume of flyash produced in 1995 was estimated at 75 mt. Without the carbon tax the volume would increase to 137 mt and with the tax to 132 mt. A tax on flyash generated can serve the coal using plants to internalise the external cost. Alongwith the tax, institutional and technical measures are needed to encourage the use of flyash in the production of bricks and cement and in road making.

Between 1994-95 and 2001-02, reduction in the rate of emissions owing to the imposition of the carbon tax on petroleum and natural gas are relatively small, about 1 percent. As already noted, the impact of price reforms in the petroleum sector on demand is also small. The gain in emission reduction has to come mainly from technical solutions such as improving the quality of engines in new vehicles, installation of catalytic converters, improved quality of gasoline and diesel, and periodical checks of vehicles for their compliance with pollution emission standards.

The above estimations of changes in the emissions are obtained at a highly aggregative level and under very strong assumptions. For example, in the coal based thermal power plants, it is well known that carbon emission factors vary with the size of plant, age of plant and the quality of coal used. In order to compute the aggregate CO_2 emissions from all coal-using plants over time, the distribution of plants by size and vintage along with the gradewise quantity of coal consumed plantwise should be known. However, information is not available.

The impact of the reforms on inter-fuel substitution have not been taken into account because of the lack of reliable estimates for all the sectors and the difficulties in estimating these parameters from the past data. One hunch is that the inter-fuel substitution effects are likely to be negligible in the short run.