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ESMAP

Energy Sector Management Assistance Progra

India
Environmental Issues in the Power Sector

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

PURPOSE

The Joint UNDP/World Bank Energy Sector Management Assistance Programme (ESMAP) is a special global technical assistance program run as part of the World Bank's Energy, Mining and Telecommunications Department. ESMAP provides advice to governments on sustainable energy development. Established with the support of UNDP and bilateral official donors in 1983, it focuses on the role of energy in the development process with the objective of contributing to poverty alleviation, improving living conditions and preserving the environment in developing countries and transition economies. ESMAP centers its interventions on three priority areas: sector reform and restructuring; access to modern energy for the poorest; and promotion of sustainable energy practices.

GOVERNANCE AND OPERATIONS

ESMAP is governed by a Consultative Group (ESMAP CG) composed of representatives of the UNDP and World Bank, other donors, and development experts from regions benefiting from ESMAP's assistance. The ESMAP CG is chaired by a World Bank Vice President, and advised by a Technical Advisory Group (TAG) of four independent energy experts that reviews the Programme's strategic agenda, its work plan, and its achievements. ESMAP relies on a cadre of engineers, energy planners, and economists from the World Bank to conduct its activities under the guidance of the Manager of ESMAP, responsible for administering the Programme.

FUNDING

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

FURTHER INFORMATION

An up-to-date listing of completed ESMAP projects is appended to this report. For further information, a copy of the ESMAP Annual Report, or copies of project reports, contact:

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India: Environmental Issues in the Power Sector

June 1998

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Preface and Acknowledgments

Environmental issues in the power sector are of major importance in India. Electric power has played a fundamental role in the economic development process. However, the most important single source of fuel for power generation has been coal, accounting for about 70% or more of electricity production; and the environmental impacts of coal-based electricity production are particularly serious, in terms of human health and well-being. The expansion of coal-based power generation affects air, land and water resources. Air pollution is a high-priority concern, because of the health consequences. The accumulation of ash at power station sites pre-empts land and endangers both ground and surface water. Furthermore, when additional coal is burned, there is an associated increase in coal production, which can degrade more land, deplete water resources and cause water pollution.

Recognizing these problems, the Government of India (GoI), the World Bank and the UK Department for International Development (DFID) have collaborated in an activity called India: Environmental Issues in the Power Sector. The counterpart for the activity was the Ministry of Power (MoP). The World Bank managed the work, with Robin Bates (IENPD) and Mudassar Imran (SASEG) as co-task managers; and contributed part of the funding, through the South Asia Region. Further substantial funding was provided by DFID, through ESMAP. Liaison with MoP on day-to-day matters was facilitated by MoP's Energy Management Centre (EMC).

The key developmental objective of this activity in the long-run is to reduce the adverse impact on the environment of power generation in India. It tries to do this through a participatory process, involving a wide range of stakeholders, and a methodology that would improve environmental planning, management and decision-making in the power sector. The report which follows describes that process and methodology; and how it was successfully applied in two important states in India (Andhra Pradesh and Bihar). The report demonstrates that a similar approach can be replicated elsewhere in India. Although a key output of the activity was the development of a decision-making tool, which enables government officials and institutions in India to evaluate alternative options for power development, the large body of data collected, the analysis conducted and the findings reported are also regarded as substantial contributions to assist the authorities in India in dealing with the adverse environmental impacts of power generation.

ESMAP and the South Asia Region are indebted to a large number of individuals and organizations involved in completing this activity. However, a special acknowledgment is necessary to DFID for its support and encouragement from the earliest stages and its commitment to the work throughout the implementation period; and to many government officials at the state and central level, especially the Department of Economic Affairs (DEA), the Planning Commission, MoP/EMC, the Ministry of Coal (MoC), the Ministry of Environment and Forests (MoEF), the Ministry of Non-conventional Energy Sources (MNES), the Central Electricity Authority (CEA), the National Thermal Power Corporation (NTPC), the Central Pollution Control Board (CPCB), the State Secretaries of Energy for Andhra Pradesh and Bihar, the State Secretary of Environment, Forests, Science and Technology for Andhra Pradesh, the State Secretary of Forests and Environment for Bihar, the Bihar State Electricity Board, Tenughat Vidhut Nigam Ltd. in Bihar, the Bihar State Hydroelectric Power Corporation, the Andhra Pradesh State Electricity Board, the Bihar State Pollution Control Board, the Andhra Pradesh State Pollution Control Board, the Environment Protection, Training and Research Institute (EPTRI) in Andhra Pradesh, and numerous individuals from academic and research institutions (notably the Tata Energy Research Institute, Indira Gandhi Institute of Development Research, Jawaharlal Nehru University, and the Indian Institute of Technology) and NGOs (especially the Integrated Sustainable Energy and Ecological Development Association).

Acknowledgments are also due to the Administrative Staff College of India (ASCI) and the Sone Command Area Development Agency (SCADA)/Metallurgical & Engineering Consultants (India) Ltd. (MECON), who carried out the Case Studies in Andhra Pradesh and Bihar, respectively; to Environmental Resources Management (ERM), the international consultants who co-ordinated the Case Studies and Special Studies and prepared the Synthesis Report; the Advisory Group for the Synthesis Report (comprising MoP, MoC, MNES, MoEF, Ministry of Petroleum and Natural Gas, CPCB, and CEA); the peer reviewers for the Special Studies, the Case Studies and the Synthesis Report; and the consultants who conducted the Special studies, namely the Tata Energy Research Institute (India), 3EC Consulting (India), Gosh, Bose & Associates Ltd (India), ERM (India), an independent Indian consultant and Water and Earth Science Associates Ltd. (funded by the Canadian International Development Agency). Finally, a vote of thanks is due to the many staff at the World Bank who generously gave their time to commenting on the work as it progressed; and provided sound advice and welcome support at timely moments. All of these parties played a critical role in contributing to the success of the work.

Abbreviations and Acronyms

ADB	Asian Development Bank
AP	Andhra Pradesh
APPCB	Andhra Pradesh Pollution Control Board
ASCI	Administrative Staff College of India
AUD	Ash Utilisation Division
BAT	Best Available Technology
BAU	Business as Usual
BHPC	Bihar State Hydroelectric Power Corporation
BSEB	Bihar State Electricity Board
BTU	British Thermal Units
CAC	Command and Control
CCGT	Combined Cycle Gas Turbine
CEA	Central Electricity Authority
CERI	Canadian Energy Research Institute
CII	Confederation of Indian Industry
CO2	Carbon Dioxide
COI	Cost of Illness
CPCB	Central Pollution Control Board
DFID	Department for International Development
DG	Directorate General
DRF	Dose Response Function
DSM	Demand Side Management
DVC	Damodar Valley Corporation
EBRD	European Bank for Reconstruction and Development
EGAT	Electricity Generating Authority of Thailand
EIA	Environmental Impact Assessment
EIPS	Environmental Issues in the Power Sector
EM	Environmental Manual for Power Development
ES	Environmental Statement
ESCO	Energy Service Company
ESMAP	Energy Sector Management Assistance Programme
FGD	Flue Gas Desulphurisation
FO	Fuel Oil
GAIL	Gas Authority of India Ltd.
GDP	Gross Domestic Product
GNP	Gross National Product
GTZ	German Agency for Technical Cooperation
GWh	Giga Watt hours
HE	Hydroelectric
HP	Hydro Power
HT	High Tension
IFS	Inter-Fuel Substitution
IGCC	Integrated Gasification Combined Cycle Plant.
IGIDR	Indira Gandhi Institute of Development Research

IIED	International Institute for Environment and Development
IPP	Independent Power Producer
kcal	kilo calorie
kt	kilo tonne
kWh	kilowatt-hour
LC	Least Cost
LNG	Liquefied Natural Gas
LOLP	Loss of load Probability
LRMC	Long Run Marginal Cost
LT	Low Tension
MATA	Multi-Attribute Trade-Off Analysis
MBI	Market Based Instruments
MMBTU	Million British Thermal Units
MNES	Ministry of Non-conventional Energy Sources
MoEF	Ministry of Environment and Forestry
MOU	Memorandum of Understanding
mt	Million Tonnes
MW	Mega Watts
NCAER	National Council of Applied Economic Research
NGO	Non Governmental Organisation
NHPC	National Hydro Power Corporation
NOx	Nitrogen Oxides
NTPC	National Thermal Power Corporation
PFBC	Pressurized Fluidised Bed Combustion
PM	Particulate Matter
pv	Present Value
R&R	Resettlement and Rehabilitation
RET	Renewable Energy Technology
Rs	Rupees
SCADA	Sone Command Area Development Agency
SDP	State Domestic Product
SEB	State Electricity Boards
SHP	Small Hydro Power
SME	Small and Medium Enterprises
SOx	Sulphur Oxides
SPBC	State Pollution Control Board
T&D	Transmission and Distribution
TEDDY	Teri Energy Data Directory & Yearbook
TERI	Tata Energy Research Institute
TOD	Time of Day
TSP	Total Suspended Particulates
TVNL	Tenughat Vidyut Nigam Ltd
TWh	Terra Watt Hours
UNEP	United Nations Environment Programme
UNIDO	United Nations Industrial Development Organisation
USAID	United States Agency for International Development
VSL	Value of a Statistical Life
WB	World Bank
WTP	Willingness To Pay

Executive Summary

Introduction

The Synthesis describes the results of an activity on India: Environmental Issues in the Power Sector. The activity was undertaken on behalf of the Government of India, through the Ministry of Power, by the World Bank, supported by funding from the UK Department for International Development. The principal outputs of the activity are: a set of analytical tools and a decision-making process that will assist power system planners in making decisions that are environmentally more sustainable; seven Special Studies; two Case Studies; and a Synthesis Report.

The decision making tool has been demonstrated in two case-study states, Andhra Pradesh (AP) and Bihar. Although no two States can adequately represent the complexity of the Indian power sector, AP and Bihar offer a good cross-section of the issues and options. Bihar is relatively poor and the Bihar State Electricity Board (BSEB) is in a particularly precarious financial and technical condition. About 40% of electricity demand comes from heavy industry; the high degree of dependence of its power sector on coal permits an in-depth analysis of the environmental impacts of coal mining and coal use in power generation; the area is comparatively remote from alternative sources of energy, although natural gas imports from Bangladesh are possible in the long run; and it has significant biomass potential. AP, on the other hand, has a wider range of supply options, including hydropower, wind and solar energy, as well as coal, and its long coastline and good ports offer better possibilities to import fuels, including LNG and coal. Agriculture accounts for some 40% of electricity demand; and the financial performance of the AP State Electricity Board (APSEB) has been better than BSEB. In both states, there is ample scope for an analysis of the whole range of policy options, including DSM and restructuring. Nevertheless, the intention is to test the tool further in other states (see below, Dissemination).

The Case Studies were supported by a set of Special Studies, dealing with: inter-fuel substitution (IFS); the welfare effects of increases in electricity tariffs; the technical and economic potential for renewable energy technologies (RETs) and demand-side management (DSM); the possibilities of adopting market-based instruments (MBIs) in India; the options available to mitigate the environmental impacts of coal-fired power stations and coal mining; and the management, disposal and utilisation of ash from thermal power plants. The Special Studies provided basic generic data to supplement the detailed state-specific information collected under the Case Studies. The Case Studies were carried out by local consultants, namely the Administrative Staff College of India (ASCI) in AP and the Sone Command Area Development Agency (SCADA) and Metallurgical & Engineering Consultants (India) Ltd. (MECON) in Bihar, co-ordinated by international consultants (Environmental Resources Management - ERM). The first six of the seven Special Studies listed above were also carried out by local consultants, under the supervision of ERM, viz. the Tata Energy Research Institute, 3EC Consulting, Gosh, Bose & Associates Ltd (India), ERM (India), and an independent consultant. The seventh was executed by Water and Earth Science Associates Ltd. (Canada), funded by the Canadian International Development Agency (CIDA).

The Synthesis Report, prepared by ERM, describes briefly the decision-making tool but focuses mainly on the results and findings of the two Case Studies, the Special Studies and relevant work carried out by others in India and elsewhere. The activity was designed to explore the environmental implications and the trade-offs implied by a range of options for power system development; and present them in a useful way to decision-makers, rather than produce specific policy recommendations. Nevertheless, the Synthesis Report does attempt to draw some lessons learned that might be relevant at the state and national level.

Methodology for the Case Studies

The structure of the decision-making tool used to conduct the Case Studies consisted of a set of linked modules. The power system planning module calculates an investment programme for power plant and a corresponding operating schedule that will meet forecast demand at least cost. The demand forecasting module is driven by a detailed examination of the historic demand and assumptions about factors that may affect the future demand for electricity at the power plant, such as system losses and tariff and income changes. The results of the power system expansion plan are linked to environmental and financial modules that produce environmental balances and financial accounts. The local environmental aspects (ambient conditions and plant siting) are examined using an air quality model. The Case Studies have demonstrated the general validity of the decision-making tool.

The power system planning and financial modules accept both financial and economic costs. The former are typically administered prices, e.g. for coals of different grades and for the transport cost per ton of coal. In practice, administered prices do not reflect adequately economic costs and provide distorted signals in terms of efficient resource allocation. Economic costs proceed from estimates of the opportunity costs of resources, and are especially relevant to the costs of building power stations, constructing ash handling facilities, mining and transporting coal, and burning coal in power stations, etc. Environmental costs were internalised and included in the estimates of economic costs, through the requirement to meet existing Indian environmental objectives, notably standards, regulations and laws governing the use of the environment; and are, consequently, handled as a fundamental and integral part of the transition in the analysis from financial to economic prices. Therefore, considerable attention has been given to ascertaining the control costs of power generation and the costs of mitigating the environmental impacts of coal mining.

In principle, most environmental impacts are internalised in the calculation of economic costs. However, certain features of the methodology need to be underlined. First, the environmental costs included as part of economic costs are not necessarily equal to the financial costs or compensation actually paid. Second, the methodology provides valuable information to decision-makers about the costs of alternative ways to meet their own environmental objectives, but does not evaluate the merits of those objectives. Information on the relationship between damage costs (including the external costs of pollution and the social impacts of resettlement and rehabilitation) and control costs, essential for such an evaluation, are not available or could not be collected to a satisfactory level of reliability under this activity. Within the activity, only two limited attempts were made to go beyond existing environmental objectives, to analyse the cost impact of alternative (World Bank) standards and the costs of CO2 reduction. Also here, no attempt was made to introduce a normative assessment of those cost impacts relative to possible benefits. Third, the methodology does not address the costs or issues related to the effective monitoring and enforcement required to apply existing standards and to financial policies to compensate for environmental damages.

In recognition of the above features, a small subset of environmental attributes has been monitored explicitly: total suspended particulates (TSP), oxides of sulphur (SO2) and nitrogen (NOx), because of their importance to air quality and human health, and the need to highlight for decision-makers the possibly serious implications of substantial increases in these attributes, which may not be addressed adequately in the long term by existing standards; carbon dioxide (CO2), because it is not subject to standards yet has an important global impact; and land use and ash, because the sheer scale of the problem in India in the future is a cause for concern, which again needs to be highlighted for decision-makers. However, the individual environmental impacts of coal mining are not tracked separately: they were costed and (to the extent possible) fully internalised within the estimates of the economic costs of coal supplied to the power stations, as described above.

The decision-making tool was used in the AP and Bihar Case Studies to explore a set of scenarios, which were designed to illuminate a number of questions. These questions are: (i) what will happen to the environment if present policy on electricity and fuel prices are maintained?; (ii) would reform and restructuring of the power sector benefit the environment?; (iii) what would be the consequences of choosing plants on the basis of economic costs, including internalisation of environmental costs?; (iv) renewable energies would improve the environment, but by how much and what would it cost?; (v) demand side management would improve the environment, but by how much and what would it cost?; (vi) what are the benefits of rehabilitating transmission and distribution networks for electricity and existing generating plant?; (vii) how much would it cost to use new clean coal technologies and to wash coal and how much would they achieve?;

(viii) can more ash from power stations be utilised and if so how?; (ix) what would it cost to implement the new World Bank environmental standards?; (x) what are the environmental impacts of power plant location and concentration?; (xi) what are the costs of environmental controls?; (xii) what are the costs of reducing emissions of carbon dioxide?; (xiii) what are the costs of environmental damage?; and (xiv) how can government intervention be used to internalise costs and in particular can market based instruments contribute to environmental management in India?

There were three main scenarios: (i) A "business-as-usual" (BAU) scenario assumed that decisions in the power sector continue to be made on the basis of administered (or financial) prices for fuels and other inputs, no fundamental tariff reform takes place, and there are no significant improvements in technical efficiency; (ii) An "inter-fuel-substitution" (IFS) scenario posited the selection of power plants on the basis of economic rather than administered input prices. Perturbations to this scenario were analysed, to isolate the impact of certain promising options, implemented individually and in bundles; and (iii) A "reform" scenario evaluated the implications of certain tariff increases and improvements in operational efficiency. No attempt was made to link reform with any particular institutional or managerial model, nor to questions of ownership.

The Process Used in the Activity

A fundamental precept of the activity was that it should be developed through a participatory process, characterised by extensive preliminary consultation and continual consultation with stakeholders thereafter. Initially, a questionnaire was delivered to senior officials in the energy and environment sector and NGOs, to obtain their views on the main issues relating to the environment in the power sector (June 1996). This was used to help focus the subsequent work on the priority issues and problems in India. Then followed a series of Workshops and Seminars in Delhi, designed to encourage the participation and interest of a wide audience and to get an early feedback on the scope, objectives and methodology of the work: a Meeting of Expert Modellers, to debate the modelling tools available to help in the analysis, which led to the selection of ASPLAN as the power system planning model for the Case Studies (July 1996); an NGO Workshop, to discuss issues of interest to NGOs and a mechanism to involve NGOs in subsequent phases of the work (July 1996); an Inception Seminar, attended by key decision makers from the Indian ministries and the power sector, at which a number of basic decisions were taken which influenced the state-level Case Studies and the Special Studies (July 1996); a Technical Workshop, bringing together the same basic audience as the Inception Seminar, to reach final consensus on methodology and modelling (October 1996); and a National Mid-Way Workshop, attended by senior officials from the central ministries, representatives of the state electricity boards, the local consultants carrying out the Case Studies and Special Studies, and representatives of NGOs (May 1997).

Parallel state-level Mid-Way and Decision-Makers' Workshops were held in Hyderabad (March 1997 and August 1997, respectively) and Patna (June 1997 and August 1997, respectively). These workshops brought together officials from the state governments, SEBs and NGOs to discuss the preliminary results from the Case Studies and exchange views on the implications of the outputs from the work. The general participation of the NGO community in the activity was further strengthened through the recruitment of a co-ordinator, in April 1997, whose role was to disseminate the results on a continuing basis and to organise workshops for NGOs; and direct liaison by the Bank with NGOs at the state and central level. The participation of the state governments in the work was further enhanced through state-level Steering Committees.

The work culminated in a National Decision Makers' Workshop and a National NGO Workshop in Delhi in May, 1998. The former was attended by representatives from state electricity boards, officials from both state and central level ministries, and individuals from academic and research institutions and from international organisations. It provided feedback on the work, which has been integrated in the Synthesis, particularly in the writing of Section 4 ("Where do we go from here?"); and permitted early dissemination of the methodology and results. The NGO Workshop provided an opportunity to a cross-section of NGOs from across India to review the issues and options considered in the Synthesis and the two Case Studies.

Finally, an Advisory Group for the Synthesis was established; and the Special Studies, Case Studies and the Synthesis Report itself have been subjected to extensive peer review. The Advisory Group, consisting of representatives of the central Ministries and agencies, met in October 1997 and April 1998, to advise ERM on the design and scope of the Synthesis Report. The panel of peer reviewers included local academics and researchers, NGOs, officials familiar with the power sector and the environmental impacts of power generation, and consultants; as well as international experts and NGOs.

Lessons Learned from the Activity

Based on the findings of the work, the following main conclusions emerge: (i) continuation of current policies and practices in the power sector is not sustainable in financial terms and will lead to even greater harmful impacts on the environment than in the past; (ii) the economic pricing of fuels, which internalises these environmental impacts, will improve the situation; (iii) options are available to ameliorate the situation further, but they need to be implemented in combination, to achieve the maximum reductions in environmental impacts; and (iv) the changes in incentives which are likely to follow from power sector reform should greatly benefit the environment.

Current Policies and Practices

Continuation of current policies and practices in the power sector is not sustainable in financial terms and will lead to even greater harmful impacts on the environment than in the past

If current tariff policies are maintained, the financial performance of the power sectors in both AP and Bihar will impose an insupportable financial burden on their respective state governments. The rate of return on capital in AP will become increasingly negative over the period, reaching -18% by 2015; and in Bihar it would average -14% from 1996 through 2015. The necessary financial injections that would be necessary from the respective state governments to ensure a minimum flow of funds to maintain and operate the sectors is unlikely to be forthcoming.

The analysis draws attention to the important relationship between the poor financial condition of the two SEBs under current policies and their inability to comply fully with environmental standards. All the thermal power plants in AP are fitted with controls to limit TSP levels, but many units, particularly the older ones, are unable to meet the standards, due to managerial and technical problems, including inadequate maintenance. In view of the fact that the older plants are unable to conform fully to environmental standards, APSEB has appealed to the AP State Pollution Control Board (APSPCB) to raise the permitted emissions limits. Similarly, in Bihar, BSEB's need for subsidy to cover its deficits prevents it funding investment out of retained earnings. Under-investment and poor maintenance lead to inadequate capacity to meet requirements, so that it is hard to close plant to maintain pollution control equipment, because of the impacts on an already low quality of service. Moreover, when there are inadequate funds for maintenance, preference will be given to actions that are necessary for operation of the plant. In such circumstances, rigorous attempts to implement existing standards are not feasible. The fundamental requirement of environmental protection is to return the power system to a position where it can provide an adequate quality of service and generate funds to make the necessary resources available for control and maintenance.

Though present circumstances make environmental compliance difficult or impossible, it was found in Bihar that the costs of doing so may be small. The Bihar case study estimates that the cost of the required measures is about Rs. 260 mn, roughly equivalent to 10 MW of generating plant. These measures would roughly halve the emissions of TSP from 2003 onwards.

In both AP and Bihar, emissions go up significantly under a "business-as-usual" (BAU) scenario. In the case of AP, they increase by about four times, and in Bihar they double. The lower growth in emissions in Bihar is because energy consumption is more severely constrained under BAU by the lack of supply. Extrapolating these conditions to India as a whole suggests that by 2014/15 the power sector in India could be producing roughly three times as much SO2, NOx, TSP and ash compared with present conditions: by that time, the ash disposal facilities around power plants would require over 1,000 km^2 of land or about one square metre per person; and CO2 emissions could be 775 mt per year, compared to 1,000 mt presently produced by power generation in the EU. These data indicate that BAU will lead to even greater harmful impacts on the environment than in the past.

Emissions on the scale described above are bound to affect air quality and have major human health impacts. The damages caused by TSP to the respiratory system are especially a cause for concern. Air quality is affected under BAU in two ways. First, the AP case study comments that TSP emissions frequently exceed standards; and air sheds around power plants in AP would currently be described as poor with respect to TSP under World Bank standards (Section 2.10.2). While these emissions could be reduced by renovating equipment in old plant, this would only be possible if APSEB had sufficient cash flow. Increased funds will also allow utilities to invest in new plants with lower unit emissions. Second, evidence from Bihar shows that, where power supply from the main system is inadequate, individuals resort to large numbers of privately-owned diesel generating sets, which suffer from high emissions of SO2 and NOx. A study which was carried out in three important commercial centres in Bihar demonstrated the significant contribution to ambient concentrations from these sources (Section 2.10).

Economic Pricing of fuels

Economic pricing of fuels which internalises the environmental impacts of power generation will improve the situation.

Shifting from financial prices for coal, as used under BAU, to economic costs, as used in the inter-fuel substitution scenario (IFS), would more than double the price of coal (from 524 Rs/t to 1350 Rs/t for Grade D coal and from 247 Rs/t to 580 Rs/t for Grade G coal in Bihar, see Table 2.31) It is estimated that the costs of environmental mitigation measures included in these costs would account for approximately 70Rs/tonne of coal mined, or 5-12% of the total economic cost of coal, depending on coal grade (Table 2.42) . Furthermore, environmental control costs add 7% to the capital cost of a conventional coal-fired power plant (Table 2.43). Using these economic costs in place of financial costs would not affect the comparative cost advantage of domestic coal in the short and medium term. For example, in both Case Studies coal from the Talcher and Sigareni coal fields continues to be part of the least-cost solution. In the long term, however, the comparative advantage of natural gas and coal imports improves, leading to their higher use in the later part of the planning period. For Bihar, this goes along with a general improvement in the environmental impact, due largely to significant imports of coal around 2008; and natural gas from Bangladesh, along with imported LNG at coastal sites towards the end of planning period. In the case of AP, the outcome is more ambiguous. Current policies were expected to lead to a number of naphtha-based IPPs. However, if planning based on economic costs is adopted, naphtha consumption is replaced mainly by imported coal and by LNG. The effect on environmental impacts is mixed - there are gains in lower ash production, but higher emissions of SO2 and NOx.

The trends identified in the Case Studies of AP and Bihar have been extended to all-India, as in the case of BAU. The major difference compared with BAU is in the generation of power from natural gas, which at the end of the period is responsible for 26% more electricity generation in the IFS scenario. This increase is at the expense of electricity generation from domestic coal (which decreases by 4% in IFS) and naphtha (which falls by 67%). This fuel switching between the IFS and BAU scenarios, stemming from the choice of fuels according to their economic costs, results in reductions in annual emissions of 3.5% for CO_2, 0.6% for SO_2, 2.8% for NOx and 3.6% for TSP by the end of the period.

However, if a substantial increase is to take place in natural gas utilisation, existing policies would need to be reconsidered. Indigenous gas is scarce in India and scarcity is managed not by prices but administered through a distortionary system of gas allocations. Gas shortages in India are likely to continue in the future, aggravated by constraints on the gas transportation infrastructure. To meet the additional requirements for natural gas from the power sector calculated above, for example, might require liberalisation of gas imports and replacing the allocation system for indigenous gas by a market-based mechanism.

Specific Measures

Options are available to ameliorate the situation further, but they need to be implemented in combination, to achieve maximum reductions in environmental impacts.

The main options considered to reduce the environmental impacts of power generation include: demand side management (DSM); clean coal technologies; coal washing; renewable energy technologies (RETs); and T&D rehabilitation. The work shows that no single option by itself would make a significant impact on the dominance of indigenous coal in power generation; and therefore the adverse environmental impacts associated with coal-based power generation. However, applying the full range of options in combination would make a substantial contribution to pollution control.

DSM

The work concludes that DSM is in general a win-win solution. In the case of AP it was found that DSM programs could reduce total system cost (in present value terms) and power consumption by about 6% by 2015. In consequence, environmental attributes decline by 9-11% (SO2 and NOx reduce by 9%; TSP and CO2 by 10%; and ash by 11%). In Bihar, the demand and cost (in present value terms) reductions are in the same order of magnitude and environmental attributes fall by about 6%. For all India, the full DSM potential is estimated to reduce environmental attributes by about 10% by 2015.

Clean Coal Technologies

Two specific clean coal technologies were considered in the case studies: PFBC in Bihar; and IGCC in AP. Both technologies have advantages in improving combustion efficiency and reducing emissions to the environment. Their disadvantages lie in higher capital and operating costs, which exceed those of conventional power plants by 10%-15% on a levelised cost basis. The benefits described in Section 2.7 suggest at best only marginal reductions in ash (none in Bihar and 2% in AP) and CO2 (3-4%) but more substantial impacts on TSP (17% in Bihar, 3% in AP), SO2 (17% in Bihar and 15% in AP) and NOx (8% in Bihar and 10% in AP), against overall increases in the present value of total system costs (2% in both states).

Coal Washing

The economics of coal washing is controversial, given the properties of Indian coal. About 15-25% of coal is lost in washing. Coal washing is therefore expensive, amounting to about 20-30% of the cost of mining coal. The Synthesis concludes that for high ash coal (i.e. with an ash content of 38% or more), transported over distances exceeding 1000 km, coal washing can be economically viable. The coal washing scenario carried out in AP highlights the trade-offs involved. Washing coal increases total system cost by less then 1%, while ash production drops by nearly 20%. On the other hand, taking into account the environmental impacts at the coal washeries, the overall requirement for the disposal of solid waste may be higher, although some of this waste may be burnt as washery tailings in a fluidised bed boiler in a power plant burning unwashed coal.

RETs

The work considered several types of renewable energy supply options. Their relative importance depends on the renewable resources in the state under consideration, as demonstrated by the case studies (with Bihar favouring bagasse and AP developing hydro and wind power). On the basis of existing knowledge, it was concluded that the overall technical potential for RET generation in India is considerable. However, the economic potential is much more limited. Also, there are major uncertainties about the likely rate of technical progress in RETs and hence different views on the possible range of future costs. In AP, system cost is estimated to increase by about 3% but lead to a reduction in all the environmental attributes in the same order of magnitude. Employing optimistic assumptions about the potential for co-generation from bagasse in Bihar it was found that environmental attributes can be reduced, by about 2% with a small decrease in system cost. A least-cost optimisation carried out for India as a whole, comparing renewable energy with other forms of generation, concluded that RETs could account for up to 4% of electricity generation capacity by 2010 (corresponding to about 36 TWh), mainly in the form of small hydro, wind and co-generation.

T&D Rehabilitation

As in the case of DSM, the work concludes that T&D rehabilitation is in general a win-win solution. Investment in the T&D networks has been seriously neglected in both AP and Bihar. Consequently, T&D losses are currently in excess of 30%; whereas it is believed that 10% losses are achievable in most states in the long run, in line with current performances in Singapore and Korea. In AP, it was estimated that investment in the transmission and distribution system that would cut overall technical losses to 10% by 2010 could lead to a 3% reduction of all environmental attributes, compared to the IFS scenario; whilst the present worth of system costs would fall simultaneously by 4%. The Bihar Case Study took less optimistic assumptions, with overall technical losses cut to 18% by 2015. Nevertheless, the present worth of system costs fell even more, by over 6%, reflecting the worse condition of the T&D system in Bihar; and the improvement in environmental attributes was commensurate, in the range 4-7% (SO2 reduces by 6%, NOx by 5%, TSP by 7% , CO2 by 6% and ash by 4%).

Combination of Options

It can be seen from the above discussion that each of the options applied individually does not have any major environmental benefits. However, when taken in combination the environmental impacts look more significant. For example, in AP, a combination of options consisting of renewables, DSM, T&D rehabilitation, coal washing and clean coal technologies, reduces coal-based power generation by 18% by 2015, compared with IFS. Total system costs (in present value terms) fall by about 4.5% with significant environmental benefits (SO2 and NOx fall by 27% and 21% respectively, while the decline in TSP, CO2 and ash is in the order of 18%). In Bihar, a mix of DSM, renewables and T&D rehabilitation reduces coal-based power generation by 15% over the same period. Total system costs (in present value terms) fall by about 7.5% with reductions in environmental impacts in the range of 4-10% (SO2 7%, NOx 4%, TSP 8%, CO2 10%). It is striking from these results that, in most cases, options which reduce local environmental damages would also help to reduce CO2 emissions, as further demonstrated by the multi-attribute trade-off analysis conducted in Section 3.

Altering Incentives

The changes in incentives which are likely to follow from power sector reform should greatly benefit the environment

The quantitative analysis of the work and, in large measure, the discussions at the National Decision Makers' and NGO Workshops, point to economic and energy sector reform as a particularly attractive alternative to BAU, even if such reform is defined very conservatively, in terms of tariff increases and improvements in operational efficiency. Notably, reform would improve the financial position of utilities and create better incentives for cost-effective power system planning: the rate of return on capital in AP quickly becomes positive; and in Bihar averages 12% rather than -14% from 1996 through 2015. The environmental performance of the energy sector is likely to benefit substantially from a more healthy financial situation, as detailed below. There was, therefore, a consensus at the Workshops that, without some measure of reform, the options may not be taken up or, if implemented, may not be sustainable. The reason is that many of the specific measures have common factors influencing their potential effectiveness, including: getting the price of electricity right (for DSM), to send correct signals to consumers to invest in efficient economic activities and appliances; getting the price of fuels right, "to create a more level playing field" (for natural gas and renewables); increasing the financial incentives of utilities (for T&D rehabilitation, coal washing, coal utilisation and ash management); and increasing the funds available to utilities (through raising tariffs).

If the adoption of clean coal technologies is to be fostered, additional measures might be necessary. They are not part of the least-cost development plan in AP and Bihar under present environmental standards. There is therefore a trade-off between emissions and costs and implementation would not proceed on the basis of normal market incentives.

The AP model clearly indicates the environmental benefits which accrue under a reform package, compared with BAU: the present values of emissions of NOx, SO2 and TSP fall by 5-7%; whilst cumulative emissions of CO2 and ash production fall by 8% and 11% respectively by 2015. Meanwhile, the demand for electricity by industry increases by 35% in 2015, compared with BAU, indicating strong concurrent economic development.

However, it should be noted that where there is now large suppressed demand, reform may increase environmental impacts, if the effect of higher prices on demand is outweighed by growth in incomes and if increased revenues permit utilities to build more power plants to meet demand. Nevertheless, the effects of reform in the Bihar model are salutary: despite meeting sales which are one-third higher by 2015 under reform compared with BAU (Table 2.37) and reducing system LOLP from 40% to 5% by 2001, environmental attributes all fall (NOx, SO2 and TSP by 11-15%, cumulative CO2 and ash by 11% and 6% respectively), indicating that the beneficial aspects of reform dominate (Table 2.38). Since non-compliant plants cannot be closed at the moment, because of the serious supply constraints, it can reasonably be expected that the higher reserve margin under reform will make the enforcement of compliance more practical. Finally, it is interesting to note again, in AP and Bihar, that there is a marked correlation between the local and global environmental benefits to pollution reduction.

In reaching the above conclusions, the work assumed the objective of complying with existing Indian standards. Hence, a "command and control" approach to environmental management was implicit, through the internalisation of the control costs. The work highlighted a number of issues which would need to be addressed before attempting to introduce market based instruments (MBIs) (Section 2.12), especially the need to ensure that the legislative and regulatory framework for administering MBIs is created. Also, power plants and companies using MBIs must have strong commercial incentives and face hard budget constraints.

Additionally, the work gave limited attention to the cost consequences of applying the new World Bank standards. Although these standards are more stringent for SO2 and particulates than existing Indian standards, the analytical results suggested that the incremental costs need not be substantial, if plants are sited appropriately. Mainly, the problem would be encountered on the side of particulates, and particulate control is relatively inexpensive. However, the work deliberately refrained from making any judgement on whether or not implementation of these alternative standards would be economically justified, particularly since the review of damage costs in Section 3.4 is inconclusive. It is important to note that delegates at the National Decision Makers' Workshop agreed that better implementation of existing standards was more important than the adoption of new and stricter standards. In other words, better implementation of monitoring and enforcement procedures might be of more immediate benefit.

Another area where the work has gone beyond Indian standards is in the cost consequences of CO2 reductions, since India has not signed the Kyoto Protocol or any other global agreements to control CO2 emissions and consequently, there are no binding targets on CO2 reduction in India. The Bihar case study investigated the supply-side opportunities for reducing CO2 through a series of carbon tax scenarios. Results show that at low tax rates (Rs. 175/ton of CO2) not much change in emissions occurs; however, as the tax rate increases to Rs. 525/ton of CO2, substantial reduction in CO2 is realised, partly as the substitution of natural gas takes place. The Andhra Pradesh case study shows that an effective way to reduce CO2 emissions is through rehabilitation of the transmission and distribution system and by implementing DSM programs. Applied in combination, these two activities could save about 12% of total expected production of CO2 over the planning horizon.

Dissemination

Two types of dissemination are envisaged for the activity on India: Environmental Issues in the Power Sector. The first is to publicise the results of the activity to a wider audience; and the second is to transfer the capability of using the decision-making tool to appropriate agencies.

In the first category, workshops would be conducted in selected states, including AP and Bihar, bringing together a wide audience of decision makers, NGOs and the general public. The goal would be to raise awareness about the availability of the tool and the issues and options involved with the environmental impacts of power generation. In particular, it will be emphasised that conventional Environmental Impact Assessments should be seen as a last resort, to try to manage those impacts, rather than minimise them or avoid them in the first place; and that use of the decision-making process and tool developed under this activity can help to anticipate those impacts, and incorporate them directly into decisions.

In the second category, selected states would be helped to actually apply the decision-making process and tool. As a first step, a Manual for Environmental Decision Making (MEDM) will be prepared, as a self-contained document, describing the objectives, methodology, outputs and interpretation of the outputs of the decision-making tool. It would be available to all organisations involved in the preparation of similar studies and would be used as a standard reference to transfer the capacity to use the tool. Given limited resources, it is recommended that active assistance in transferring and applying the tool should be targeted initially towards states where the power sector is being restructured. The likelihood of seeing effective results will be much higher in such states. A critical step towards replicating the successes of the Andhra Pradesh and Bihar Case Studies will be to build the human resource capacities in these other states to use the model. Where states are restructuring, a suitable counterpart agency could be the regulator or grid company. Of course, the regulator or grid company would either have to develop in-house capacity to use the tool or else to manage consultants to use it on their behalf, and then integrate the results of the tool into their indicative power system planning. As part of the second category of dissemination, there could in the training phase be a rapid application of the tool, to achieve two results: (i) demonstrate the application of the tool, using actual data from the state in question; and (ii) test further the extent to which the results of the AP and Bihar Case Studies have wider applicability in India.

FINAL REPORT

India: Environmental Issues in the Power Sector: *Synthesis Report*

June 1998

This report has been prepared by Environmental Resources Management (ERM) on behalf of the World Bank with funding from the UK's Department for International Development (DFID)

Environmental Resources Management

1 *WHY THIS WORK HAS BEEN DONE*

Electricity is essential to modern life and to economic development. All countries aim to ensure a supply of electricity that is affordable, reliable and secure. Developing countries consume far less electricity per person than do developed countries and it is impossible to envisage any path of development that does not require a many-fold increase in the amount of electricity used.

The production of electricity has important consequences for the global, regional and local environment. The generation of electricity from fuel by combustion releases carbon dioxide that contributes to global warming and climate change. India is already a major producer of carbon dioxide in aggregate, although its production per capita is small. Developed countries have already taken a disproportionate share of the carrying capacity of the atmosphere, but it is developing countries which will be the main incremental source of greenhouse gases over the next several decades. It is also cheaper to save a marginal unit of carbon dioxide in developing, rather than developed countries.

Fossil fuels contain small amounts of sulphur and nitrogen that when burnt produce acid gases; oxides of nitrogen are also formed by the combination of nitrogen and oxygen in air at high temperatures. Small particles are produced during combustion from ash in the fuel, from pyrolysis and from recombination of carbon atoms. Acid gases and particulates from electricity generation are dispersed by high stacks, but eventually they reach the ground and can damage health and property. Except for a few places in India, the contribution of the power sector to ambient concentrations of acid gases is not large. The sector is frequently responsible for excessive concentrations of particulates.

Acid gases can be transported long distances across frontiers and are eventually precipitated as acid rain. Oxides of nitrogen are also precursors of tropospheric ozone, so high local concentrations of ozone can originate from remote sources. These trans-boundary problems are well documented in Europe and North America and have lead to stringent controls to reduce emissions. The problems are not yet severe in India, but the large increases in coal fired power generation that are expected, could change this picture.

India has large reserves of coal that are a major asset. They mostly have a high ash content, up to 40% or more. Disposing of the ash by-product is troublesome; the requirement for land is huge and leaching can contaminate ground water. Most forecasts of energy use in India show rapidly rising use of local coal, so the problem will get worse if nothing is done. Coal ash can be used in many ways and it may be appropriate to encourage this practice so as to minimise the environmental impacts.

Sites for hydro and thermal power stations and for ash disposal require large areas of land. Hydro power stations are inevitably on rivers and thermal power stations also require cooling water, so the necessary land is generally of economic value. The resettlement of populations, though more properly a social, rather than environmental issue, is an important constraint on new development. The two issues are often practically inextricable.

Given these significant social and environmental impacts of power development it is reasonable to ask what can be done to mitigate or avoid them and what it would cost. The environmental impacts of power development may be reduced by using less electricity, by controlling the impacts of generation, by preventing waste products reaching the environment or by adopting new, intrinsically clean technologies. Energy conservation is an alternative to new power supply. Renewable energies are an alternative to fossil-fuel generation.

These measures cannot be studied in isolation. If three power stations are envisaged in one State then the same set of energy conservation activities cannot be used to challenge all of them. Whereas the market in the state for ash-bricks to replace clay bricks may be sufficient to absorb the ash from one plant it may not be enough to handle three. A holistic vision is necessary to see how the possibilities in terms of supply, demand and control can be best combined. The objective is to find a suitable balance between the needs for power and the preservation of the environment over the long-term.

The means and effectiveness of implementation depend on the structures and capabilities of institutions. The power sector in India is on the verge of fundamental and significant reforms. It is moving slowly from a publicly owned, vertically integrated, monopolistic system with highly distorted prices for fuels and electricity to a more liberal system with market prices, competition and commercial motivations. These changes will affect the environment. They will affect the demand for electricity, the financial viability of the entities involved, the capacity of the state to influence action, the viability of all market based policies and the choice of fuel and technologies. The changes will rebound on the relationships between fuel suppliers and the power sector and between the power sector and its regulators. Market based instruments may supplement or replace command and control mechanisms for regulation.

It is necessary to understand how these structural changes will affect the environment and to identify how the opportunities can be maximised and any threats averted. One important aspect of the structural changes that are in motion is the decentralisation of the decision making process to the State level. The practice in the past is that planning has been made at the national level by the CEA using the regions as the planning unit. The States contributed to this with load forecasts and indications of likely economic and industrial development. They have not in the past carried out power system expansion planning. Any effective decentralisation will require that the State Electricity Board (SEB) acquire either the capacity to perform that function themselves or sufficient understanding to be an "informed buyer" of such services from an independent institution. This change requires the development of planning tools that are appropriate to the State level. It is important that the environmental impacts of the power sector be properly recognised in any planning exercise and the development of new tools to support State level planning also creates the opportunity to ensure that the environment is fully incorporated into the planning tools and processes.

In recognition of this need and its opportunities, the present work has been undertaken on behalf of the Government of India, through the Ministry of Power, by the World Bank, supported by funding from the UK Department for International Development. The principal outputs of this work are a set of analytical tools and a decision-making process, that will support power system planners in making decisions that are environmentally more sustainable; seven Special Studies; two Case Studies; and a Synthesis Report. In particular, the analytical tools and decision-making process can help decision makers in India: (i) improve the planning and management of their power systems, taking into account the major environmental impacts; and (ii) assess more explicitly the economic and environmental trade-offs involved between different options for power generation. The tools are also able to exhibit clearly any residual impacts that may be of interest and that may not have been fully internalised.

The decision making tool has been demonstrated in two States, Andhra Pradesh and Bihar. From this demonstration some empirical evidence has been obtained concerning the effectiveness of various environmental policies. That evidence is resumed here along with some other important studies within and outside the country and a tentative extrapolation of the findings is made to all India.

1.1 *THE QUESTIONS THAT ARE ASKED*

The work that has been done addresses the practical questions of where the power sector is going, what the consequences will be, what can be done to reduce the impacts on the environment and what it will cost. The Synthesis is structured around a set of questions that arise from the discussion in the preceding section. They are:

- what will happen to the environment if present policies on electricity and fuel prices are maintained?
- would reform and restructuring of the power sector benefit the environment?
- what would be the consequences of choosing plants on the basis of economic costs including internalisation of environmental costs?
- renewable energies would improve the environment, but by how much and what would it cost?

- demand side management would improve the environment, but by how much and what would it cost?
- what are the benefits of rehabilitating transmission and distribution networks for electricity and existing generating plant?
- how much would it cost to use new clean coal technologies and to wash coal and how much would this achieve?
- can more ash from power stations be utilised, and if so how?
- what would it cost to implement the new World Bank environmental standards?
- what are the environmental impacts of power plant location and concentration?
- what are the costs of environmental controls?
- what are the costs of reducing emissions of carbon dioxide?
- what are the costs of environmental damage?
- how can government intervention be used to internalise costs, and in particular can market based instruments contribute to environmental management in India?

1.2 *THE METHODOLOGY*

1.2.1 *An Overview of the Work*

The work that underlies this Synthesis Report comprises two detailed Case Studies at State level in Andhra Pradesh and Bihar, a set of cross-cutting Special Studies and other relevant work done in India and elsewhere on the topic. The Case Studies look in detail at the interaction of technical options for managing demand, controlling impacts and using clean technologies. They also track how reform and restructuring of the electricity sector may affect the environment.

The Special Studies expand upon key issues covered in the Case Studies and this Synthesis Report. They deal with the possibilities for Inter-Fuel Substitution, the Welfare Effects of increases in electricity tariffs, the technical and economic potential for Renewable Energies and Demand Side Management, the possibilities of adopting Market Based Instruments in India, the costs of available Mitigation Options for Coal Power Stations and Coal Mines and the Management of Ash from Thermal Power Stations.

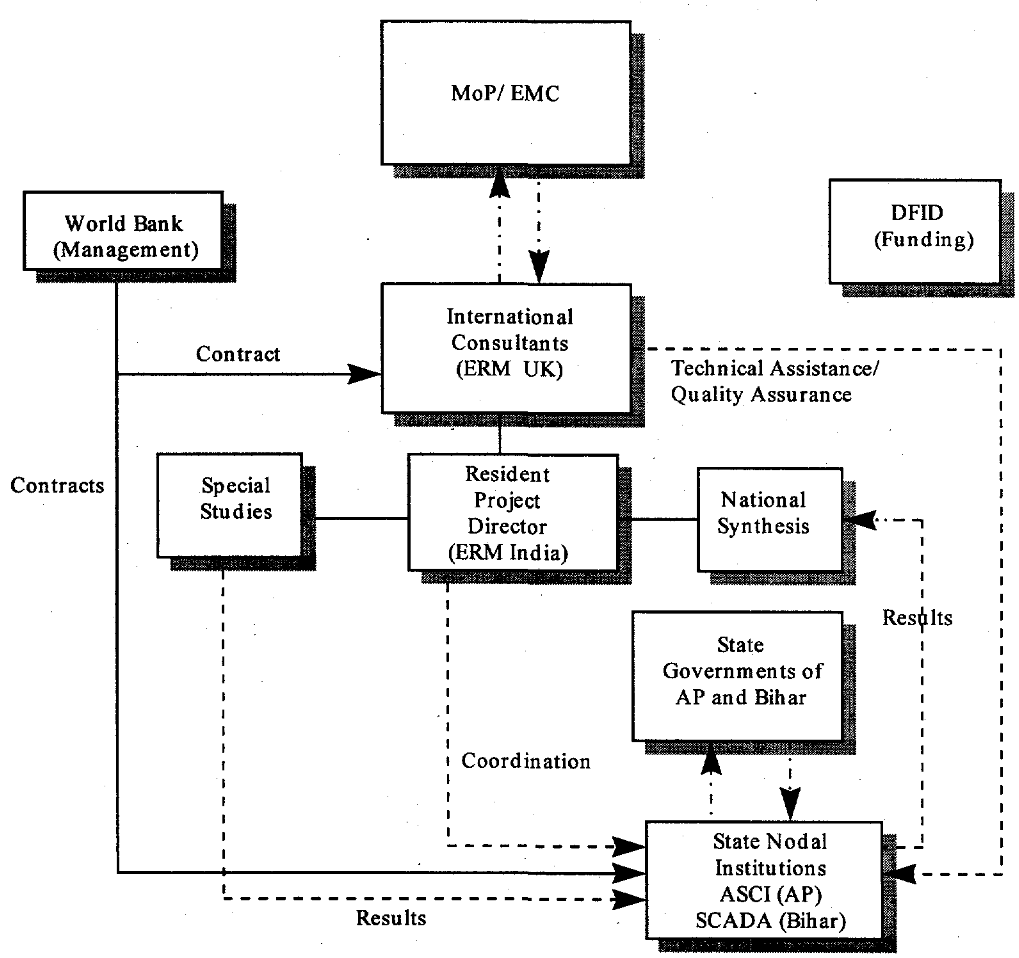
Andhra Pradesh and Bihar were chosen for the Case Studies. No two States can adequately represent the richness and complexity of the Indian sub-continent, but these two States exhibit some of the important characteristics. Bihar is a relatively poor State and the SEB is in a precarious financial and technical condition. A large part of demand for electricity comes from heavy industry. There are large coal reserves nearby and the area is comparatively remote from alternative imported sources; it has useful reserves of biomass. Andhra Pradesh is a largely agricultural State; it has a reasonably well performing SEB and with its long coastline and good ports has the option to import fuels; it also has appreciable wind and solar resources.

The Case Studies explore a set of scenarios based on the questions posed in *Section 1.1*. The questions, and therefore indirectly the scenarios, form the organising framework for this synthesis.

1.2.2 *The Organisation and Process*

The process employed to do the work was chosen to help achieve the principal objective which was to create an effective and acceptable decision making tool. The process was therefore characterised by extensive preliminary consultation and continual consultation thereafter. The organisation of the study is shown schematically in *Box 1.1*.

Box 1.1 Organisation of the Study



The initial stage of the work began with the design of a questionnaire which was subsequently delivered to a large number of senior officials in the energy and environment sector and to NGOs. The questionnaire sought to obtain the views of decision makers and interest groups on the main issues relating to the environment in the power sector. This was used to aid in focusing the subsequent work toward issues and problems considered to be most pressing in India.

The work was then launched in earnest with a series of three Workshops and Seminars designed to encourage the participation and interest of a wide audience. One workshop, for a technical audience, was used to encourage debate on the modelling tools available to help in the analysis. Another workshop was attended by NGOs who were invited to open a discussion of the most appropriate issues and analysis and to nominate individuals to represent them at subsequent workshops. These were followed by a major
Inception Seminar attended by key decision makers from the Indian ministries and from the industry. A number of key decisions were taken at the Seminar which formed the basis for state-level Case Study analysis and for the Special Studies.

Mid-Way Workshops were undertaken in each of the two states - Bihar and Andhra - and a combined workshop took place in Delhi. The latter was attended by senior officials from the central ministries, representatives of the state electricity boards, teams from the state-level nodal institutions (ASCI and SCADA) and representatives of the NGOs. These workshops discussed the preliminary results from the Case Studies and exchanged views on the implications of the outputs from the work.

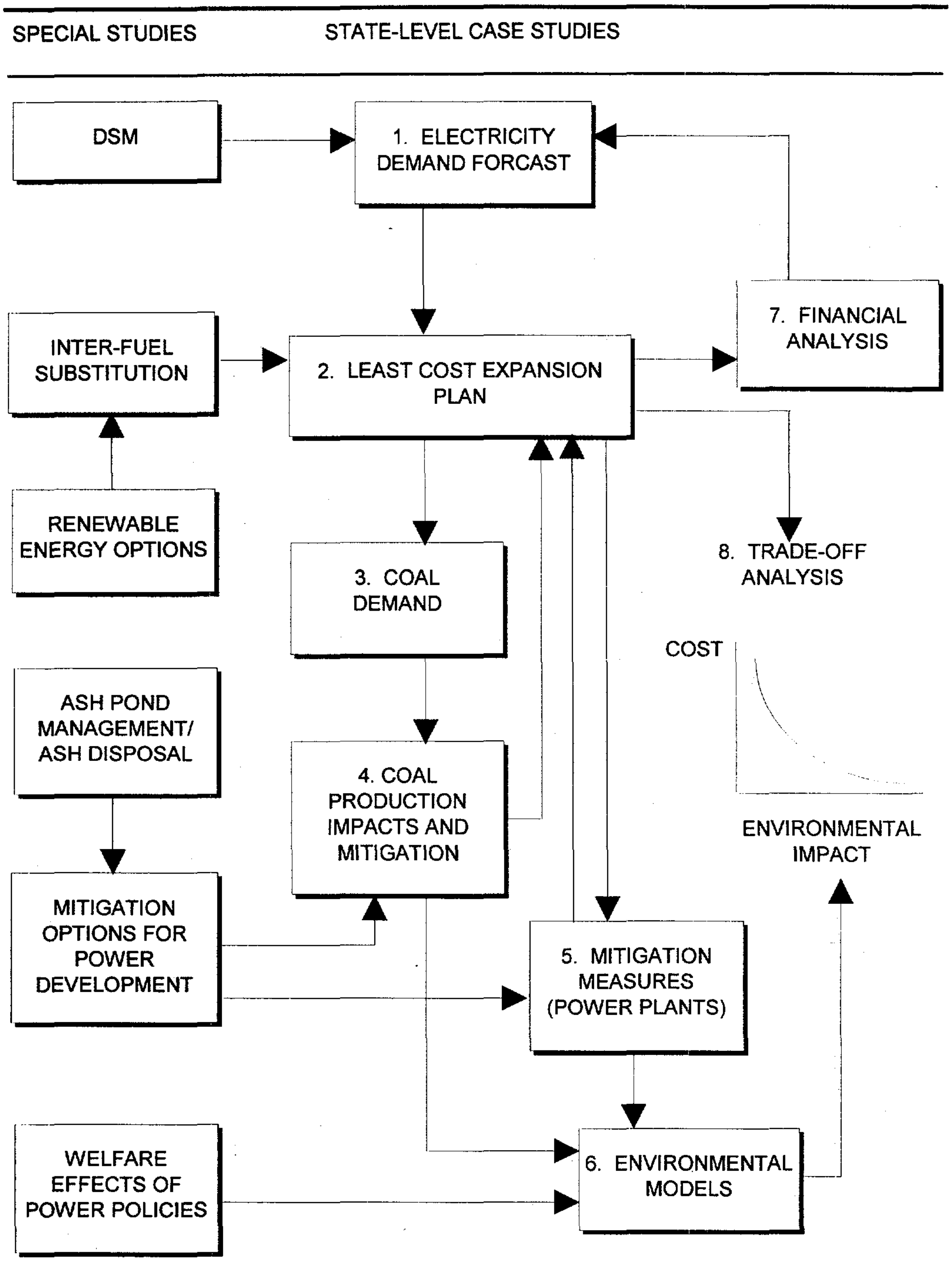
The participation of the NGO community was encouraged through the recruitment of a co-ordinator whose role was to disseminate the intermediate results and to organise workshops.

The work culminated in a Decision Makers Workshop and an NGO Workshop. The former was attended by representatives from a number of state electricity boards, officials from both state and central level agencies, academic and research institutes, and from international organisations. This final Decision Makers Workshop will help to disseminate the methodology established as part of the project and demonstrate the value of the methodologies in other states in India. The NGO Workshop will provide an opportunity for a cross-section of NGOs from across India to review the issues and options considered in the Synthesis Report and the two Case Studies.

1.3 *The Decision Making Tool*

The structure of the decision making tool proposed, at the outset of the work, is shown in *Figure 1.1*. It was originally envisaged as a set of linked modules. The power system

Figure 1.1 Structure of the Decision-Making Tool



Note: A Special Study was also conducted on MBI's

planning module calculates the schedule of investment in power plant that will meet forecast demand at least cost. In this study it uses a least-cost power system expansion planning software, ASPLAN, which combines a capacity-planning model with load manipulation and scenario comparison algorithms. The software uses a probabilistic simulation algorithm to estimate the system production costs. The load curve parameters, for example, specifications on peak and off-peak periods and seasonalities, along with hourly load data, were entered into the programme to define the load pattern. A production cost simulation was then carried out for the resulting capacity additions. The model carried out dynamic programming optimization which takes into consideration a set of parameters such as reserve margins, reliability constraints and loss of load probability.

The demand forecasting module is driven by a detailed examination of the historic demand and assumptions about factors that may affect the future demand for electricity at the power plant, such as price rises under Reforms, DSM programmes and rehabilitation of T&D networks.

The output from the power system expansion plan is linked to environmental and financial modules that produce environmental balances and financial accounts. A 12% discount rate was used to calculate present values. The local environmental aspects are examined using an Air Quality Model.

It was initially expected that the work would lead to the specification of a particular set of modules that could be adopted as a decision making tool for use by any State level institution. During the course of the work it became clear that the modular character of the decision making tool lent itself to a variety of choices for the components. The work undertaken for the Case Studies adopted certain common modules, but even in this situation some divergence developed in the approach to load forecasting and the financial analysis. Both Case Studies used the same power system planning module, but in similar applications elsewhere it is possible that a different power system module would be chosen.

Rather than defining a single appropriate model as a decision making tool, the work has demonstrated the general validity of the analytical structure underlying *Figure 1.1*. The work has also demonstrated a decision making tool comprising a particular set of modules that works well and is available for use by others, but more important is the demonstration of the validity of the analytical approach.

1.4 THE ENVIRONMENTAL ATTRIBUTES

People and things are affected in numerous and complex ways by the emissions from the power sector. To simplify discussion, it is helpful to adopt a set of measurable attributes that can be accepted as proxies for the complex and extensive set of environmental impacts. A choice of attributes underlies the design of any standard or market based instrument for pollution control. For that purpose it is essential that the attributes be measurable. For the purpose of anticipating the future it is also necessary that the attributes can be predicted from the modelling process.

1.4.1 *Internalisation of Costs*

The environment is used by businesses and consumers as a means of disposing of wastes. Businesses seek to make their products at the lowest cost. Minimising production costs could mean paying little attention to reducing environmental impacts and thereby imposing high damage costs on others. Environmental regulation has adopted the principle of the "polluter pays". In this case the polluter is obliged to pay to reduce the impacts below a reasonable level.

The government sets rules for the use of the environment that affect the costs incurred by the business. Technical standards are a common instrument; in this case the business must change its operations or introduce controls that reduce some environmental attribute to a prescribed level; these controls increase the costs of the business. Market based instruments may also be used, in this case a tax is imposed on an environmental attribute (for example the carbon tax) or a licence is purchased to allow a certain level of discharge (for example the systems of tradable permits used in some cases in the US).

The process by which costs are imposed on businesses to reduce environmental impacts to an acceptable level is known as "internalisation" of environmental costs. If the rules of environmental management were adequate and enforced, then all the costs would have been internalised and a proper balance between economic activity and the environment would automatically be achieved. The approach adopted in this work is to internalise as far as possible all environmental costs. Therefore considerable attention has been given to ascertaining the control costs of power generation and the costs of mitigating the environmental impacts of coal mining. Environmental impacts to water are internalised by the imposition of discharge standards; emissions to air are internalised through the imposition of emissions standards and the need to satisfy air quality standards; the land use aspects are contained in the economic cost of acquiring land; and the impact of resettlement and rehabilitation is internalised through the economic costs imposed by the regulations. The present standards in India for air quality are given in *Table 1.1.*

Table 1.1 Existing MOEF Standards for Air Quality

	Residential/ Rural Areas			**Industrial/ Mixed Areas**		
Air Quality Standard, (mg/m^3)	SO_2	NOx	SPM	SO_2	NOx	SPM
24 hour Average	80	80	200	120	120	500
Annual Average	60	60	140	80	80	360

Thus, as far as possible, the environmental costs are handled as a fundamental and integral part of the transition in the analysis from financial to economic prices. The power system planning and financial modules described earlier (*Section* 1.3) accept both financial and economic costs. The former are typically administered prices, e.g. for coals of different grades and for the transport cost per ton of coal. In practice, administered prices do not reflect adequately economic costs and provide distorted signals in terms of efficient resource allocation. Economic costs proceed from estimates of the opportunity costs of resources, and are especially relevant to the costs of building power stations, constructing ash handling facilities, mining and transporting coal, and burning coal in power stations, etc. For example, opportunity costs reflect the value of foreign exchange and labour (to handle concerns about employment effects and import content), land pre-empted by ash ponds and coal mines, and the compensation required for resettlement and rehabilitation. Environmental costs were internalised and included in the estimates of economic costs through the requirement to meet existing Indian environmental objectives, notably standards, regulations and laws governing the use of the environment.

To illustrate the scale of possible distortions created by financial prices and the importance of using economic costs, work reported later concludes that the shift from financial prices for coal to economic costs would more than double the price of coal (from 524 Rs/t to 1350 Rs/t for Grade D coal and from 247 Rs/t to 580 Rs/t for Grade G coal in Bihar, see *Table* 2.31); and the costs of environmental mitigation measures included in these costs would account for approximately 70 Rs/tonne of coal mined, or 5-12% of the total economic cost of coal, depending on coal grade (*Tables* 2.41 *and* 2.42). Furthermore, environmental control costs add 7% to the capital cost of a conventional coal-fired power plant (*Table* 2.43). However, even with internalisation, the comparative cost advantage of domestic coal remains robust in the short and medium term.

In principle, most environmental impacts are internalised in the calculation of economic costs. However, certain features of the methodology need to be underlined. First, the environmental costs included as part of economic costs are not necessarily equal to the financial costs or compensation actually paid. Second, the methodology provides valuable information to decision-makers about the costs of alternative ways to meet their own environmental objectives, but does not evaluate the merits of those objectives. Information on the relationship between damage costs (including the external costs of pollution and the social impacts of resettlement and rehabilitation) and control costs, essential for such an evaluation, are not available or could not be collected to a satisfactory level of reliability under this activity. A review of existing information is however presented and evaluated in *Section* 3.4. Within the activity, only two limited attempts were made to go beyond existing environmental objectives, to analyse the cost impact of alternative (World Bank) standards and the costs of $CO2$ reduction. Also here, no attempt was made to introduce a normative assessment of those cost impacts relative to possible benefits. Third, the methodology does not address the costs or issues related to the effective monitoring and enforcement required to apply existing standards and to financial policies to compensate for environmental damages.

In recognition of the above features, a small subset of environmental attributes has been monitored explicitly at critical points in the analysis:

- Total suspended particulates (TSP), oxides of sulphur (SO2) and nitrogen (NOx) are tracked because of their importance to air quality and human health, and the need to highlight, for decision-makers, the possibly serious implications of substantial increases in these attributes, which may not be addressed adequately in the long term by existing standards;
- Carbon dioxide (CO2) is tracked, because India has no environmental objectives regarding GHG reduction, so CO2 (which has an important global impact) is not subject to standards; and
- Land use and ash are treated explicitly, because the sheer scale of the problem in India in the future is a cause for concern, which again needs to be highlighted for decision-makers.

Although the internalisation of environmental costs implies a "command and control" approach to environmental objectives, some discussion of the potential for Market Based Instruments (MBIs) in India and the constraints to implementation are given in *Section 2.12*. There is considerable theory and some experience that suggests that MBIs would offer a more efficient mechanism of internalising costs, by allowing polluters to equilibrate the marginal costs of abatement according to their circumstances.

Implicit in this paradigm is that ownership of business is not relevant. Both private and public producers must meet their responsibilities under the law, so the costs are internalised in both cases. To a first approximation this should be true in any reasonably well enforced system of standards. There might also be some behavioural differences. Private industry might try to avoid control costs whereas the public service motivation of the public sector would cause standards to be scrupulously observed. Alternatively, it might be that complicity between state institutions would cause regulators to be more tolerant to state than to private industry. It is possible that different modes of behaviour would predominate in different countries. In India there is some evidence that courts are ineffective against State owned enterprises.
There are several SEBs with court orders made against them because of their environmental impacts, but where no action has been taken because the plants cannot be shut down without disconnecting consumers and the State government has not the funds to bring the plant into compliance.

It is certainly clear that ownership would influence the effectiveness of market based instruments. MBIs are ineffective where there is no commercial incentive or hard budget constraint because the organisation affected has no reason to adjust its behaviour if it can simply pass on the costs or obtain compensation through budgetary subsidies. There is further discussion of this in *Section 2.8* which considers the possibility of introducing MBIs to help manage the environmental impacts of the discharge of ash from power stations.

1.4.2 *Choice of Attributes*

The attributes chosen for this study are of three types. In some cases the present value of emissions is calculated over the study period. This attribute is appropriate for emissions that do not accumulate, but cause acute damage; an example is the effect of TSP or SOx on human health. The present value of the investments required to reduce emissions can be compared to the present value of the reduction in emissions to give an estimate of the unit cost of emission reduction. A second type of attribute is the cumulative emission of materials that are not destroyed. An attribute like this is appropriate when the impact is a consequence of a "stock" rather than a "flow". Examples are the radiative forcing properties of carbon dioxide which depends on the total amount in the atmosphere or the management of coal ash where the problems depend on the amount accumulated.

Specifically the set of attributes used are:

- the present value of emissions of particulates and oxides of sulphur and nitrogen from specified sets of plant (tonnes);
- cumulative emissions of carbon dioxide (tonnes CO_2);
- cumulative production of ash (tonnes);
- cumulative land pre-emption (m^2).

Other environmental impacts, including emissions to water, are local in character. The work handles these by calculating the costs of meeting existing standards and thereby internalising the costs. The resettlement and rehabilitation impacts of the sector are similarly treated; the costs of acquiring land at market prices and of compensating resettled people at the official prescribed rates, are taken to be a true reflection of the external costs.

1.5 *The Institutional Framework*

The State Electricity Boards have primary responsibility for the distribution of electricity within the states. These are predominately state owned although the two in Bombay and Calcutta are privately owned. The SEBs have their own generation but have increasingly come to purchase power from central organisations including The National Thermal Power Corporation (NTPC) and National Hydro Power Corporation (NHPC). The transmission of electricity at the central level is the responsibility of the power grid corporation. NTPC, NHPC and Power Grid are all owned by the Government for India.

Planning of the sector is formally undertaken by the Central Electricity Authority (CEA) in co-ordination with the Planning Commission. The planning has gradually become more decentralised as the financial limit for approval of power projects by CEA has been raised.

Environmental regulation and monitoring is undertaken by The Central Pollution Control Board (CPCB) at a central level and The State Pollution Control Boards (SPCB) at the state level. The CPCB sets minimum standards across all of India while the SPCBs can impose stricter standards in their own states.

Scenarios have been constructed to help respond to the questions posed in *Section 1.1*. *Figure 2.1* contains a summary of the assumptions underlying each scenario. The exact interpretation differs slightly in Andhra Pradesh and in Bihar, but the principles are the same for both.

The following sections examine the implications of these scenarios for the power system and the environment. They draw mainly on the Case Studies, but also on the Special Studies and other material that is available about energy and the environment in India.

Figure 2.1 Environmental Issues in the Power Sector Main Scenarios for the Case Studies

Scenario	General Description	Purpose	Electricity Tariffs	SDP Growth	Fuel Costs and Purchased Power [1]	T&D Losses	DSM, RET	Captive Plants & supply constraints
BAU	No policy changes	Analyses consequences of pursuing current and expected policies.	Current policies and those currently approved and expected to be implemented	SDP projections based on current economic policies and those approved and expected to be implemented	Fuel choice based on existing real prices (financial) and price increases based on policies currently approved and expected to be implemented [2]	Loss projections based on current investment and management policies and those currently approved and expected to be implemented [3]	Current policies and those currently approved and expected to be implemented	Captive plant increases steadily through a reference year and then held constant. Supply constraints increase.
Economic Reform	Not tied to any specific institutional framework but leading to reform of prices and improvement in operational efficiency	Explores the implications of reforming the power and coal sectors	LRMC based tariffs or approximation to these	SDP projections assuming economic reform takes full effect by 2002 [4]	Price levels and price structures assumed to be based on economic costs and expressed in real terms [5]	Losses fall as commercial incentives come into play	Conservative estimates of RET costs in least-cost analysis. DSM driven only by tariff reform	Captive power plant and supply constraints eliminated by a reference year.
IFS	Traditional supply-side planning based on economic input prices	Highlights the choice between fuels, concentrating more on conventional fuels.	As for BAU	As for BAU	As for Economic Reform	As for BAU	RET as for Economic Reform scenario. DSM driven by tariff increases, if any.	As for Economic Reform [6]
Green [7]	A variant of IFS with more detailed consideration for DSM and alternative technologies	To examine the environmental benefits and costs of 'green' [8] options.	As for BAU	As for BAU	As for Economic Reform	As for BAU	Make optimistic assumptions about RET and DSM [9]	As for Economic Reform.

Scenario	General Description	Purpose	Electricity Tariffs	SDP Growth	Fuel Costs and Purchased Power (1)	T&D Losses	DSM, RET	Captive Plants & supply constraints
Alternative Standards	World Bank emission standards	Analyses the cost and environmental consequences of applying an alternative set of standards within the IFS scenario	As for BAU	As for BAU	As for Economic Reform	As for BAU	As for IFS.	As for Economic Reform.
CO_2 reduction	Implications of reducing CO_2 below IFS levels	Derive cost-curve for CO_2 reduction	As for BAU	As for BAU	As for Economic Reform	As for BAU	As for IFS	As for Economic Reform

Notes:

1. Shadow pricing is unnecessary in any scenario. In the BAU scenario, all prices and costs are financial and no attempt is made at shadow pricing. In the non-BAU scenarios, costs of fuel and purchased power are priced at economic cost; therefore shadow pricing is unnecessary.
2. In constant 1995/96 prices.
   Imported fuel prices should take account of any expected 'real' changes in prices (ie changes in price at constant 1995/96 price levels).
   The reduction in the import duties on coal to 5% should be taken into account in the BAU scenario. The impact of the deregulation of coal grades E, F and G is not sufficiently certain to include in the BAU scenario.
   Purchased power tariffs should mirror, to the extent possible, the fixed and variable structure of the actual tariffs.
   Purchased power tariffs should reflect any future 'real' increases or decreases in prices. If, for example, the price is fixed in nominal terms then the price will fall over time in 'real' terms.
3. Losses would be expected to increase over time if current policies and practices are pursued and the transmission and distribution systems become increasingly overloaded.
4. SDP growth may quicken as the result of improved availability and quality of electricity supply.
5. Environmental costs assumed to be internalised. Current environmental standards assumed to be met.
6. Financial constraints on investment not considered in this scenario.
7. Variant 'cases' should look separately at DSM and RET policies.
8. The benefits and costs should be based on broad considerations of all alternatives to traditional supply-side options. These have loosely been labelled 'green'.
9. Also extended ash utilisation should be assumed. This should be handled off-line.

2.1 *WHAT WILL HAPPEN IF PRESENT POLICIES ON ELECTRICITY AND FUEL PRICES ARE MAINTAINED?*

The prices for electricity and fuels in India are distorted and this has consequences for the environment. Electricity is often sold to agricultural consumers at prices that are well below the costs of production. This practice leads to waste of electricity and also impairs the finances of the SEBs. The poor financial condition of the Boards may make it difficult to maintain plant properly, especially the environmental control equipment which is not essential to plant operation.

The distorted prices for fuels for power generation affect the environment if they encourage the use of domestic resources with relatively high environmental impacts and discourage cleaner imported fuels.

The Business as Usual (BAU) scenario explores what happens if India continues with the present approach to pricing fuels and electricity. It poses two subsidiary questions:

- what will be the environmental consequences of this approach?
- will the power sector be able to fund its expansion in an efficient and adequate manner?

2.1.1 *The BAU Scenario*

The BAU scenarios adopted for Andhra Pradesh and Bihar differ slightly in detail, but both assume a minimum of change in the management of the electricity sector. The electricity tariffs reflect current policies and those anticipated. In Andhra Pradesh the interpretation is that the realisation for the agricultural sector will double in four consecutive years, reaching 48 paises/kWh by 2000. In Bihar the agricultural realisation reaches 27 paises/kWh by 2003 and remains at that level until 2015. All prices are in real terms.

The assumptions for Andhra Pradesh are optimistic and amount to modest reforms in that they foresee substantial commitment of IPPs, some price increases and efficiency improvements.

2.1.2 *The Evidence from Andhra Pradesh*

The Power System

The power system of Andhra Pradesh comprises nine thermal stations, fourteen hydro plants and some wind turbines. The installed capacity in the State is 5258 MW made up of 2661 MW hydro, 2453 MW coal thermal, 100 MW gas and 44 MW of wind power. In addition to this capacity the State has been allocated 897 MW of output from plants in the central sector including 580 MW from the National Thermal Power Corporation (NTPC), 277 MW from Neyveli Lignite Corporation and 40MW from the Madras Atomic Power Station. The total capacity available to the State is 6155 MW.

Among the larger plants on the system, are the coal fired plants at Vijayawada (3 x 420 MW), Kothagudam (240 + 210 + 220 MW) and Ramagundam (420 MW). The plant at Vijayawada burns coal from the Talcher coal field in Orissa, the other two plants burn coal from the Singareni coal fields in Andhra Pradesh. The major hydro plants are at Srisailam (7 x 110 MW), Nagarjunasagar (1 x 110 + 7 x 100 MW) and on the lower Sileru (4 x 115 MW).

Andhra Pradesh has enjoyed a favourable hydro-thermal mix in the past but the share of hydro relative to that of thermal has been declining from about 48% in 1990/91 to about 22% in 1995/96. The main reason for this is the absence of any attractive large hydro projects in the State; subsidiary reasons are the shorter lead-times of thermal plant, the desire to maximise the use of local coal and the high political and transaction costs associated with hydro developments. The system suffers at present from a shortage of peaking power. Hydro is presently used to cover this requirement.

Captive power in the State has mainly been in the iron & steel industry, cement and chemicals. Both capacity and generation has increased rapidly in recent years because of the falling reliability of the grid. The present installed capacity is about 925 MW generating 3745 GWh of energy.

The APSEB faces severe financial and structural constraints. Despite a high level of technical and operational performance, there is an acute shortage of generating capacity and inadequate revenues. The origins of these problems are various; the tariff level is low and the structure distorted, there are high levels of technical and non-technical losses, and the billing and collection is poor.

Although the present installed capacity is inadequate, there is considerable committed capacity within the State and private sectors. These include 1800 MW of coal thermal capacity, 450 MW of gas and 800 MW of naphtha based generation. Most of the gas, naphtha and wind and some of the coal are independent power plants.

Historic Demand

It is important to understand the historic development of demand, especially when, as generally in India, there are substantial technical and non-technical losses and unmetered consumption that are difficult to distinguish. In reviewing the historic data, particular attention was paid to developing means of estimating these quantities. The energy sales, estimated unrestricted demand and load shedding as assessed in the Case Study for the past ten years, are given in *Table 2.1*.

Table 2.1 ***Historic Demand and Load Shedding in Andhra Pradesh (TWh)***

Year	Energy sales	Estimated Demand	Load Shedding
86-87	11.63	12.05	0.42
87-88	11.53	12.61	1.08
88-89	12.9	14.16	1.27
89-90	14.26	15.89	1.63
90-91	15.92	16.99	1.07
91-92	17.57	18.71	1.15
92-93	19.02	20.47	1.45
93-94	21.71	23.56	1.85
94-95	23.56	24.19	0.63
95-96	23.88	27.91	4.03

Source: Andhra Pradesh Case Study, ASCI Consultancy, 1998.

Load shedding has remained around 10% of load for much of the period, improved slightly in 94-95, but then deteriorated rapidly in 95-96. This is consistent with the increase in captive generation in recent years that was noted earlier. Most of the load shedding is in industry. There is no cumulative load shedding in agriculture because although power is often not available to farmers, in aggregate they have enough to pump all the water they require.

Load shedding is an external cost; it prevents manufacture of goods and reduces the wealth of the population. Environmental improvements should go hand-in-hand with improved reliability.

Demand Forecast

The energy demand forecast has been made using a trend extrapolation of total electricity demand and then allocating that demand to different sectors using exogenous sector shares(1). The BAU scenario envisages only changes in the tariff that appear to be politically feasible in the present context in Andhra Pradesh.

- the price of electricity to agriculture doubles in four consecutive years
- the price to residential consumers increases by 20% over the same period
- industrial prices remain constant as they are already close to long run marginal cost.

(1) The value of demand forecasting is limited to a degree by available data and future uncertainty.

In detail, the assumptions regarding tariff and price elasticity are summarised in *Table* 2.2.

Table 2.2 Price and price elasticity assumptions for BAU

Sector	Industry	Commercial	Domestic	Agriculture
Price elasticity				
	-0.3	-0.4	-0.4	-0.2
Tariff (Rs/kWh)				
Reference year				
	3.00	3.00	1.65	0.06
96-97	3.00	3.00	1.65	0.06
97-98	3.00	3.00	1.82	0.06
98-99	3.00	3.00	2.00	0.12
99-00	3.00	3.00	2.00	0.24
00-15	3.00	3.00	2.00	0.48

Source: Andhra Pradesh Case Study, ASCI Consultancy, 1998.

Demand at the bus-bar in the service region of Andhra Pradesh is forecast to increase under BAU assumptions from 37,600 GWh in 1997 to about 140,000 GWh by 2015. Peak demand is estimated to increase from 6000 MW to over 21,700 MW in the same period. The share of agriculture declines slightly in the total, but remains the largest component. All other components increase slightly.

T&D losses in the Andhra Pradesh system have stabilised recently at about 20% but maybe as high as 32%; they are envisaged to fall in BAU to 15% by 2015. Because of the poor reliability of the system, captive generation is assumed to increase to 20% by 2001 and then remain at this level until the end of the period.

Committed and Candidate Plants

A substantial volume of new, mostly private, generating capacity was envisaged as committed. The plants concerned are shown in *Table* 2.3

Table 2.3 Committed Plants

Name	Year of Commissioning	Capacity (MW)	Fuel
Jegurupadu I & II	1997	140 + 78	gas
Kakinada I & II	1997	92+116	gas
Vijjeswaram I & II	1997	60 + 110	naphtha
Hyderabad Metro I	1999	250	naphtha
Ramagundam	2000	260	Talcher coal
Vishakapatnam	2000	520 + 520	Talcher coal
Krishnapatnam	2000	500	Talcher coal
Hyderabad Metro II	2000	400	naphtha

Source: Andhra Pradesh Case Study, ASCI Consultancy, 1998.

The candidate plants considered for the power system expansion are coal fired plants at load centres and pit-heads, supplied from Talcher and Singareni; indigenous gas; naphtha and imported coal and gas. It is considered that there are no new large hydro plants within Andhra Pradesh that are cost-effective; there are some small sites on irrigation canals and these are considered later as renewable energy. Details of the candidate options are given in *Table 2.4*

Table 2.4 Candidate Plants

	Capacity	Financial Capital Cost (kRs/kW)	Ht Rate at Minimum Load (BTU/kWh)	Incremental Ht Rate (BTU/kWh)
Singareni (pit head)	500	40	11200	9745
Talcher (pit head)	500	64	11200	9745
Singareni (load centre)	250	43	11200	9745
Talcher (load centre)	250	43	11200	9745
Imported Coal (coastal)	250	43	10640	9260
Naphtha	400	35	7000	6985
Gas	116	32	9000	8862
LNG	232	32	9000	8862
Hydro	110	35		

Source: Andhra Pradesh Case Study, ASCI Consultancy, 1998.

The capital cost of the pit head plant at Talcher includes the costs of the high voltage transmission line to evacuate power from the site.

Fuel Costs and Availability

The financial costs of fuel for the principal existing plants and for the different candidate options are given in *Table 2.5.*

Table 2.5 Financial Costs of Fuels (BAU)

	Cost of Coal (Rs/t)	Cost of Transport (Rs/t)	Total (Rs/tonne)	Gross of Loss (Rs/t)	Calorific Value (kcal/kg)	Fuel Cost (Rs/MMBtu)
Existing & Committed						
VTPS - Tal'	366	576	942	1130	3300	86.3
KTPS - Sing'	545	82	627	753	3300	57.5
RTPP - Sing'	545	437	982	1178	3300	90.0
Vizag	366	331	697	836	3300	63.8
Future coal						
Talcher PH	366	45	411	493	3300	37.6
Sing' PH	545	45	590	709	3300	54.1
Talcher LC	366	575	941	1129	3300	86.2
Sing' LC	545	250	795	955	3300	72.9
Other Fuels						
Imp'd Coal	2115	300	2415	2415	6000	101.4
Naphtha	6170	250	6421	6421	10500	154.1
LNG						136.5

VTPS is Vijayawada Thermal Power Station
KTPS is Kothagudam Thermal Power Station
RTPP is Ramagundam Thermal Power Plant

Source: Andhra Pradesh Case Study, ASCI Consultancy, 1998.

The availability of energy resources for each candidate option was assessed on the basis of the various technical and infrastructure constraints that are likely to operate during the planning period. The estimated availability is given in *Table 2.6.* The assumptions are important because fuel substitution in the model often occurs because cheaper fuels are exhausted.

Table 2.6 Assumptions on Incremental Fuel Availability (mt)

	to 2001	2002-2006	2007-2011-	2011+
Coal				
Singareni	3.6	3.2	2.3	
	(800)	(700)	(500)	
Talcher	3.6	6.8	9.0	9.0
	(800)	(1500)	(2000)	(2000)
Imported	2.3	6.8	11.3	11.3
	(750)	(2250)	(3750)	(3750)
Hydrocarbons				
Indigenous gas	1.2	0.4		
	(600)	(200)		
LNG		3.6	4.8	4.8
		(1800)	(2400)	(2400)
Naphtha	1.8	2.3	2.3	2.3
	(1200)	(1500)	(1500)	(1500)
Fuel Oil	0.6	0.9	1.5	1.5
	(300)	(450)	(750)	(750)

Note: the figures in parentheses indicate MW equivalents

Source: Andhra Pradesh Case Study, ASCI Consultancy, 1998.

The availability of coal was estimated by a detailed matching of requirements and sources of supply that extended beyond the borders of the State. Details may be found in the Case Study.

The Expansion Plan

The optimal expansion plan shows the following patterns:

- pit-head and load-centre plants using Singareni coal are preferred because of their access to low cost fuels, but the option is quickly exhausted because of constraints on production;
- indigenous gas is attractive, but is quickly exhausted;
- pit-head plants at Talcher are the next best option; the number of plants that can be supported at Talcher is limited;
- as the possibilities of pit-head plants are exhausted for resource and locational reasons, it becomes necessary to import coal and LNG;
- imported coal and LNG have similar levelised costs therefore a reasonable mix of both options was adopted.

The system reliability improves very rapidly in this scenario. This is because of the large volume of committed plant that is expected to be built within the next three years. The assumption that this plant will all be completed on time is strong and the forecast system reliability may be optimistic. *Table 2.7* shows the development of system reliability. The loss of load probability shows the probability (expressed as a percentage) that capacity will be insufficient to meet demand.

Table 2.7 System Reliability

Year	1996/97	2001/02	2006/07	2011/12	2014/15
Reserve Margin (%)		1.5	6.4	7.9	8.4
Unserved Energy (GWh)	4599	155	101	114	135
Loss of Load Probability (%)	71.7	4.1	1.2	2.3	2.2

Source: Andhra Pradesh Case Study, ASCI Consultancy, 1998.

Electricity Production by Fuel

The fuel-burn resulting from this expansion programme is summarised in *Table 2.8.*

Table 2.8 Fuel Consumption in Various Years

Year	Talcher Coal	Coal from AP	Local Gas	Naphtha	Hydro	Imported Coal	LNG	Total
TWh								
1996/7	8.4	13.8	1.5		9.4			33.0
2001/2	15.0	15.0	2.7	6.3	9.4			48.2
2006/7	18.6	27.8	7.6	7.1	9.6			70.8
2011/2	48.1	30.7	7.5	8.8	9.6	1.4		106.1
2014/5	56.5	31.9	4.9	5.7	9.6	18.7	7.9	135.5
(%)								
1996/7	25.3	41.7	4.6		28.4			
2001/2	31.0	31.0	5.5	13.0	19.4			
2006/7	26.3	39.4	10.7	10.1	13.6			
2011/2	45.3	29.0	7.1	8.3	9.1	1.3		
2014/5	41.8	23.6	3.6	4.2	7.1	13.8	5.8	

Source: Andhra Pradesh Case Study, ASCI Consultancy, 1998.

Despite the penetration of LNG and imported coal, Indian coal not only remains the mainstay of the system as a proportion of generation, but the volumes consumed increase over the period by a factor of four. Indian coal remains about the same fraction (60-65%) of power generation throughout the period. Within that fraction there is a major shift from in-state supplies to cheaper coal from Talcher. The declining share of hydro is compensated first by indigenous gas and committed naphtha plants and then by imported coal and LNG.

Part of the large increase in coal production from Talcher is transported to load-centre plants and part is burnt at the pit-head. The distribution is determined by the relative costs and practical constraints on the rate of building at different sites.

The demands on the coal transportation system will increase greatly. The railways struggle already to meet the existing requirements and their capacity to respond to the future need is problematic.

Financial Consequences

The average incremental cost of bulk supply over the period is calculated as 1.77 Rs/kWh. The average incremental cost of delivered energy to the consumer is calculated at 2.02 Rs/kWh. The projections of the financial performance under the BAU scenario suggest that the average revenue will be 1.84 Rs. / kWh and that the Board will lose money over the period. The domestic and agricultural tariffs are especially far below the cost of supply. The loss is exacerbated because the cost of power from the new IPPs that serve the incremental load is higher than the cost of power from APSEB's existing plant. Such a situation is not sustainable. By 2014/15 the annual loss will have reached 55 billion rupees. *Table 2.9* shows the rate of return on capital employed which is forecast for selected years of the period. The deterioration in performance is evident.

Table 2.9 Rate of Return on capital employed (% per annum)

Year	Return (BAU)
1996/7	3.6
2001/2	-7.2
2006/7	-6.8
2011/2	-15.6
2014/5	-127.7

Source: Andhra Pradesh Case Study, ASCI Consultancy, 1998.

Environmental Impacts

The environmental impacts of the BAU scenario are summarised in *Table 2.10.*

Table 2.10 Emissions to the Environment

Year	CO_2 mt	NOx kt	SOx kt	TSP kt	CO_2 kg/kWh	NO_x g/kWh	SOx g/kWh	TSP g/kWh
1996/97	25	166	168	17	0.65	4.4	4.4	0.46
2001/02	36	221	218	22	0.75	4.6	4.5	0.45
2006/07	56	353	338	34	0.80	5.0	4.7	0.49
2011/12	92	592	589	59	0.85	5.6	5.8	0.56
2014/15	118	784	774	71	0.85	5.8	5.7	0.57

Source: Andhra Pradesh Case Study, ASCI Consultancy, 1998.

The emissions of carbon dioxide rise steeply from about 25 mt per year in 1997 to 118 mt per year in 2015. Part of the rapid rise occurs because of the increase in electricity production (both to meet new demand and also to satisfy that demand which is presently unserved) and part occurs because electricity production becomes more carbon intensive. The explanation for this is that the share of hydro-power in generation is falling rapidly (from 28% in 1997 to 7.1% in 2015) and this is a more important influence on emissions of carbon dioxide than is the use of LNG towards the end of the period.

Specific emissions of SOx and NOx per unit of electricity generated, rise over the period for similar reasons. The specific emissions of sulphur increase more steeply towards the end because imported coal is assumed to be 1.5% sulphur content (1). Total emissions of these acid gases rise exponentially and are four times the 1997 level by 2015. Ground level concentrations of oxides of sulphur comply with requirements in most parts of India. The local impacts at ground level of the increase in emissions can probably be accommodated by careful siting of new power plant without exceeding ambient norms and without requiring control equipment. Exceptions are likely in pit-head locations where many power plant are concentrated, and in industrial areas if the emissions from a new power plant add to an existing high background level. More detailed evidence for these conclusions is given in *Section 2.10* concerning siting.

Emissions of TSP grow more slowly than related impacts such as carbon dioxide and ash because electrostatic precipitators (ESPs) are renovated and new generating plant are fitted with high efficiency precipitators that remove 99.7% of fly-ash. Ash discharge rises from 6 million tonnes per year in 1996/97 to about 26 mt per year in 2014/15; the total discharge of ash in the period is 254 mt. The land required to dispose of this ash in ash-ponds would be about 2000 hectares.

(1) The sulphur content of imported coal maybe less than 1.5%.

A variant case of BAU was examined to investigate the possibility that T&D losses are under-reported and are absorbed into the reports for unmetered agricultural sales. This view gains support from the observation that while the connected agricultural load has grown at an annual rate of 13.8% the reported energy consumption has grown at 17.6%. This alternative view suggests that T&D losses, far from being 18.8% of production, as officially estimated by APSEB, may be as much as 32.2%. In these circumstances the projected financial performance under BAU is even more dismal than before; because the true present sales, and therefore the future potential income, are less. Environmental impacts fall only slightly from the main BAU case.

2.1.3 *The Evidence from Bihar*

The Power System

The Bihar State Electricity Board (BSEB) supplies power throughout the State, except in the area of the Damodar Valley Corporation (DVC), where it supplies only low voltage customers. Two other power companies have been created in Bihar; the Bihar State Hydroelectric Power Corporation (BHPC) that manages a set of relatively small hydro plants, and Tenughat Vidyut Nigam Ltd. (TVNL) that was set up to construct and manage the Tenughat thermal plant in Damodar valley. It has recently been decided that the plant will be taken over by the NTPC. Substantial purchases of power are made from NTPC; during 1994/95, BSEB accounted for only 28% of the total supply to Bihar.

In any power system planning study where power to an area is supplied by different companies it is necessary to decide on a boundary for the analysis. In this case the boundary is drawn around the BSEB supply area to include TVNL and BHPC plans. DVC's plants are excluded from the expansion study, but purchases from DVC are included in the electricity balance. Environmental impacts from plants are allocated to Bihar in proportion to the amount of electricity that they supply to Bihar whether they are located within or outside the state. Details of the plant considered are given in *Table 2.11*.

Some of the problems confronting the BSEB are evident from this Table. The thermal plants are old, obsolescent and poorly maintained. They have been de-rated, but the actual availability in 1995/96 was less than half of even the de-rated capacity. The 2 x 210 units at Tenughat were not commissioned in 1995/96.

Bihar State Electricity Board (BSEB) is in a poor financial condition. Its liabilities considerably exceed its assets; investment outlays have fallen steadily from Rs. 2.04 bn in 1989/90 to Rs. 0.9 bn in 1995/96. Its operations required an estimated subsidy from the state of Rs. 7.83 bn in 1996. The rates of technical and non-technical losses are high and its power stations are in chronic disrepair. Environmental control equipment receives low priority in the allocation of resources for maintenance. The suppressed demand in 1994/95 has been estimated at 2373 GWh, mainly in agriculture; this is more than the 2050 GWh sent-out from BSEB's plants.

Table 2.11 Generating Plant Supplying Bihar

Plant	Fuel	Nameplate Capacity (MW)	Derated capacity (MW)	1995/96 Availability (MW)
BSEB				
Patratu	Coal	840	770	295
Barauni	Coal	320	310	140
Muzzaffarpur	Coal	220	220	60
Kosi	Hydro	19	19	4
Subernrekha		130	130	130
Total		1529	1449	629
BHPC	Hydro	58	58	12
Tenughat	Coal	420	420	0
Central Sector				
Farraka	Coal	482	482	482
Kahalgaon	Coal	256	256	256
Talcher	Coal	170	170	170
Chukka	Hydro	94	94	94
Total		1002	1002	1002
Grand Total		3009	2929	1643

Source: Bihar Case Study, SCADA, 1998.

The ambient air quality around the main BSEB plants is well within the norms for SO2 and NOx, but close to the limit of 500μg/m^3 for TSP that is permitted around industrial sites. The limit is sometimes exceeded at Patratu TPS. The emissions of particulate matter exceed the statutory limits of 150 mg/m^3 at all plants. The measured emission concentrations are between 240 mg/m^3 at Barauni TPS and 625 mg/m^3 at Patratu TPS. The entry concentrations of fly ash into the ESPs are higher than the design values because the coal that is delivered, is well below design specification. The plants are mainly designed for E grade coal and actually receive G grade coal (or even ungraded coal). Poor maintenance of the control equipment also impairs performance.

Demand Forecast

The demand forecast covers the geographical area of BSEB, as described earlier. The starting point is the present level of sales and some considerable analysis is necessary to determine this, because of losses and unmetered sales.

Energy generation by captive units in heavy industry in 1994/95 has been estimated by the Case Study at 2912 GWh. Most of this (2400 GWh) is in the iron and steel industry and is unlikely ever to be supplied by the grid. The remaining 512 GWh are potentially substitutable by grid supplies. Analysis of past consumption patterns for other consumer groups suggests that the total suppressed demand is around 2373 GWh, made up as shown in *Table 2.12.*

Table 2.12 Estimate of Suppressed Demand in BSEB Service Area

Sector	Suppressed Demand (GWh)
domestic	103
commercial	182
agricultural	1154
LT industry	224
HT industry >25 kV	512
HT industry @ 11 kV	198
TOTAL	2373

Source: Bihar Case Study, SCADA, 1998.

This suppressed demand is added to the served demand, and the sum is the basis for the load forecasting. The load forecast is made using an econometric model and forecasts of State Domestic Product (SDP) and price, together with assumed income and price elasticities. In the BAU scenario the growth of SDP is estimated as 3.5% to 2002, 3.75% from 2003 to 2007 and 4.5% thereafter. Differentiated growth rates are adopted for sectors. The tariff in the residential sector is assumed to increase at 2.5% per year from 1998 to 2003 and then to remain constant thereafter. For agriculture an increase of 10% per year over the same period is assumed and again constant prices after 2004. The absolute levels by sector are shown in *Table 2.13.* It is evident that the unit revenue from agriculture remains very low. The cross-subsidy from industry to residential and commercial sectors remains.

Table 2.13 Sales Tariffs in BAU (Rs/kWh)

	1997	1998	1999	2000	2001	2002	2003-15
Residential	1.10	1.12	1.15	1.18	1.21	1.24	1.27
Commercial	1.45	1.45	1.45	1.45	1.45	1.45	1.45
LT Industrial	2.20	2.20	2.20	2.20	2.20	2.20	2.20
HT Industrial	2.14	2.14	2.14	2.14	2.14	2.14	2.14
Agriculture	0.15	0.17	0.18	0.2	0.22	0.24	0.27
Street lighting	1.40	1.40	1.40	1.40	1.40	1.40	1.40
Other	2.00	2.00	2.00	2.00	2.00	2.00	2.00

Source: Bihar Case Study, SCADA, 1998.

The adopted price and income elasticities are summarised in *Table 2.14.*

Table 2.14 Price and Income Elasticities in the BAU Scenario

Sector	Own price elasticity	Income elasticity
Domestic	-0.3	1.75
Commercial	-0.26	1.27
Industrial	-0.2	1.50
Agriculture	-0.2	1.50

Source: Bihar Case Study, SCADA, 1998.

Technical and non-technical losses are very high (about 28% and 9% respectively). In agriculture, non-technical losses are two-thirds and in domestic, nearly one-third. In BAU it is expected that technical losses will deteriorate further, to 30%, because of a lack of investment in infrastructure.

On the basis of these assumptions and the econometric model, the unrestricted system maximum demand is estimated to rise from 2252 MW in 1996 to 6937 MW in 2015 and the consumption to increase from about 12 TWh in 1996 to 33 TWh in 2015.

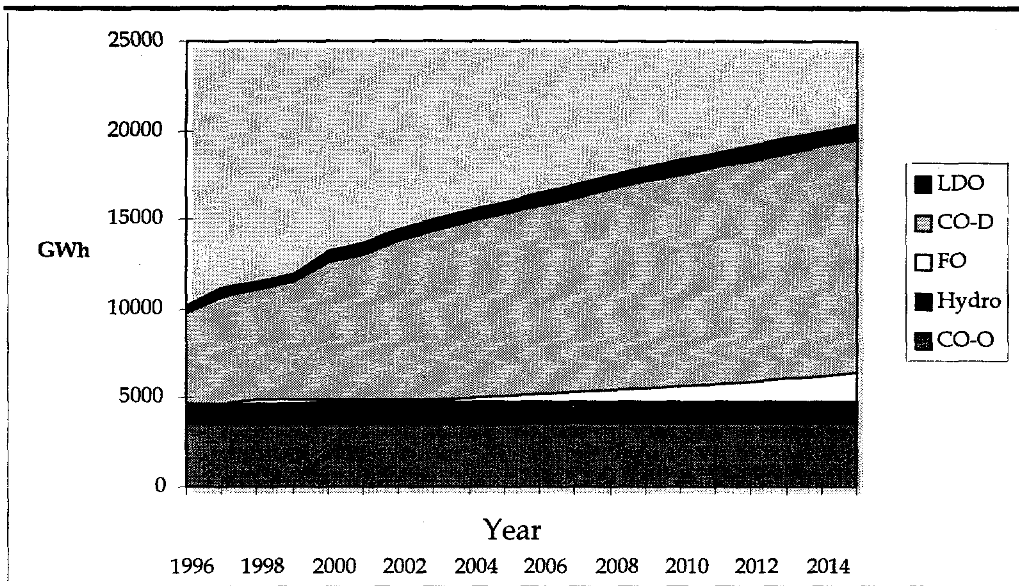
Committed Plants

Because of the precarious financial situation, the capital programme envisaged in the BAU scenario is modest. Only a minimum of emergency works is undertaken at the existing BSEB power stations; two units of 67.5 MW coal based plants are installed at Patna and the 2 x 210 MW extension of the Tenughat TPS under NTPC is commissioned. The take up of BSEB's entitlements from NTPC is limited by the financial constraints. Coal and diesel based captive plants for which applications are pending with BSEB are considered as committed plants. Coal based new captive plants of 585 MW are assumed; the capacity is based on the proposition that 50% of the incremental HT industrial load will be met by these plants. Similarly, 530 MW of new captive diesel generators are assumed to meet 50% of the new commercial load.

The Expansion Plan and the Generation by Fuel

The expansion plan is completely determined by the input assumptions described above. There are no candidate plants to be added by the least cost expansion programme. The power system model calculates only the generation by plant, the production cost and the system reliability. The sources of electricity by fuel are shown in *Figure* 2.2 and according to plant owner in *Figure* 2.3.

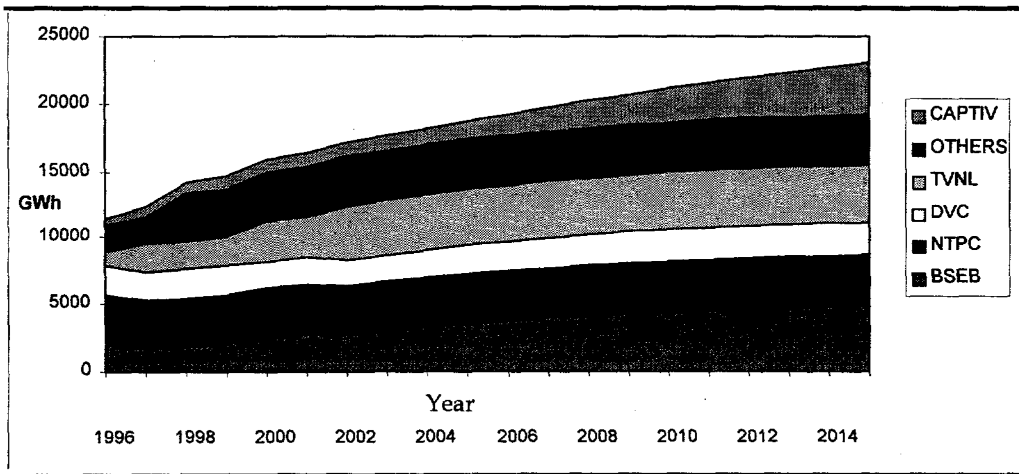
Figure 2.2 Generation by Fuel in Bihar (BAU)



Source: Drawn from results of Bihar Case Study, SCADA, 1998.

In the key, LDO refers to distillate fuels, FO to fuel oil. CO-D refers to coal from within Bihar and CO-O refers to coal from outside Bihar. A little natural gas is burnt, but it is imperceptible on the *Figure* 2.3. The Figure is remarkable for the low growth and the heavy reliance on local coal.

Figure 2.3 Generation by Owner in Bihar (BAU)



Source: Drawn from results of Bihar Case Study, SCADA, 1998.

NTPC purchases have been assumed stable because of the inability of BSEB to pay for the power that it takes. It is surprising, given the pessimistic basis of the BAU scenario that the consumption more than doubles over the period. There is a large increase in the output from TVNL; although this plant is now owned by NTPC it is assumed that the output will be available to Bihar despite its low capacity to pay. The increased output from BSEB is due partly to the new coal fired plant at Patna and partly to the effects of the emergency rehabilitation of existing plant. The most striking aspect of the Figure is the dramatic increase in captive power generation induced by the incapability of the BSEB to supply.

Nevertheless, the increased output is far from enough to meet demand and the reliability of the system in the BAU scenario deteriorates disastrously. The quality of service falls from an already poor loss of load probability (LOLP) of 41% in1996 to 85% in 2015.

Financial Consequences

The average incremental cost of bulk supply over the period comes to 1.31 Rs/kWh. The average incremental cost of delivered energy over the period is 1.91 Rs/kWh. The average unit revenue is 1.83 Rs/kWh. Evidently such a large margin between unit costs and unit revenues is not sustainable. Other financial indicators tell the same story. The average rate of return on assets over the period is -14%; the average debt service coverage ratio is -0.61.

Environmental Consequences

All environmental attributes rise over the period, roughly doubling by 2015 and restrained by the fact that within this scenario there is little scope for more generation. The specific emissions (i.e. per kWh) of SO_2, CO_2, NOx and TSP are stable. Environmental attributes for selected years are shown in *Table 2.15*.

Table 2.15 Emissions to the Environment in Bihar

Year	CO_2 mt	NOx kt	Sox kt	TSP kt	CO_2 kg/kWh	NO_x g/kWh	SOx g/kWh
1996/7	13.9	80.7	90.6	60.2	1.23	7.2	8.0
2001/2	18.0	102.6	117.0	80.0	1.19	6.8	7.8
2006/7	22.2	124.0	145.3	98.6	1.22	6.8	8.0
2011/2	25.6	141.4	169.3	114.3	1.24	6.8	8.2
2014/5	27.3	148.9	181.4	121.1	1.23	6.7	8.2

Source: Bihar Case Study, SCADA, 1998.

The specific emissions for Bihar are higher than in Andhra Pradesh because of the poor level of plant performance and the smaller contribution from hydro.

The analysis draws attention to the important relationship between the poor technical and financial condition of the BSEB under BAU and its inability to comply with environmental standards. The requirement of BSEB for subsidy to cover its operation prevents it funding investment out of retained earnings; its poor financial condition makes it ineligible for PFC funding. Even if funds were available it would be hard to close plant to maintain pollution control equipment because of the impacts on an already low quality of service.

Moreover, when there are inadequate funds for maintenance, preference will be given to actions that are necessary for operation of the plant. In such circumstances rigorous attempts to implement existing standards are not sufficient. The fundamental requirement of environmental protection is to return the power system to a state where it can provide an adequate quality of service and generate adequate funds to make the necessary resources available for control and maintenance.

Though present circumstances prevent compliance, the costs of doing so are small. The cost of the required measures is about Rs. 260 mn; it is roughly equivalent to 10 MW of generating plant. The breakdown according to mitigation measure is shown in *Table 2.16.* These controls would roughly half the emissions of TSP from 2003 onwards; they would have little effect on SO2 and on NOx, but the emissions of these pollutants and the ambient concentrations are within present norms.

2.1.4 *Evidence from Other State Level Studies*

We are not aware of any comparable work that seeks to analyse at State level the future environmental impacts of the power sector.

2.1.5 *The Implications for All-India*

The trends identified in the Case Studies of Andhra Pradesh and Bihar have been extended to all-India using the Environmental Manual for Power Development (EM). The EM is a modelling system developed by the World Bank with funding from the GTZ and the DFID.

Table 2.16 Mitigation Measures and their Costs

	Mitigation measure	Rs. Mn	Problem
Barauni TPS	wastewater treatment	40	no effluent treatment of plant wastewater and ash pond discharge
	complete installation of ESP and ash handling system on units 4&5	38	ESP and ash handling partially erected, but not commissioned
	augment ESP and ash handling system on units 6 & 7	50	ESP not operating satisfactorily
Muzzafarpur TPS	wastewater treatment	20	no effluent treatment of plant wastewater and ash pond discharge
Patratu TPS	augmentation of ash pond	50	suspended solids above limit; ash pond needs enlargement
	wastewater treatment	60	no effluent treatment of plant wastewater and ash pond discharge
Total		258	

The analysis of all-India was based on the demand forecasts prepared by the CEA for each region up to 2012; these were extrapolated through to 2015. The CEA has also prepared indicative plans for the capacity expansion needed to meet this demand; they are contained within the Fourth National Power Plan: 1997-2012. These forecasts distinguish hydro, nuclear and thermal plants, but not the fuels used in the thermal plants. The growth in electricity demand was calculated using the following methodology:

1. The CEA's (1) demand forecasts were projected through to 2014/2015 and 15% was added to allow for transmission and distribution losses. These loss assumptions are low compared to those that have been measured in State level studies.

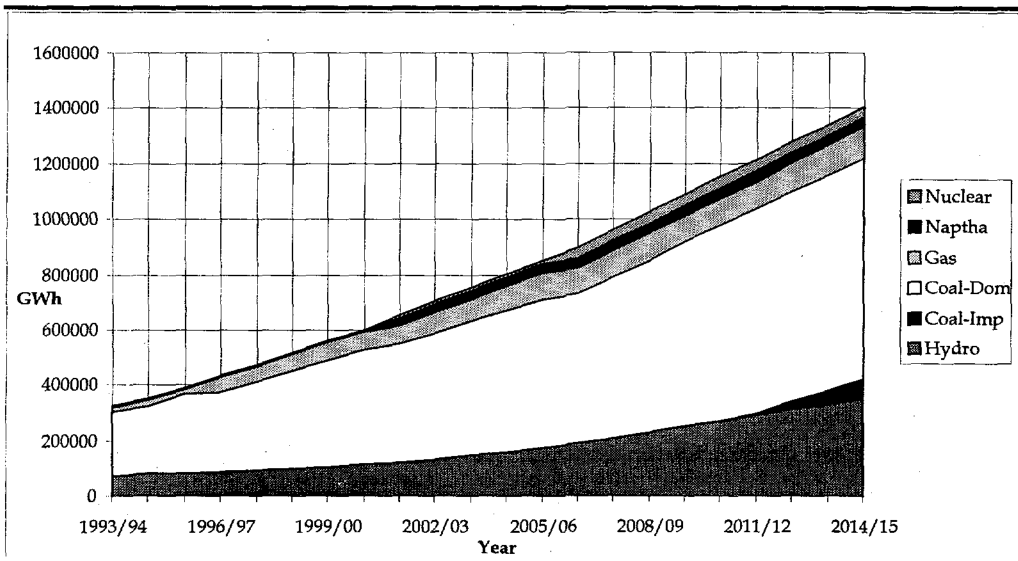
2. The CEA's historical MW and GWh data for the years 1993/94 and 1994/95 was used to calculate the typical load factor for hydro and nuclear power plants in each region (2) . However, as the load factor for nuclear power plants has historically been very low (typically only around 25%), it was assumed that any new nuclear capacity operated at a 57% load factor (or 5,000 hours per annum) (although this may be optimistic). These figures were then used to forecast energy production from hydro and nuclear power plants through to 2015 using the CEA's capacity forecasts ("*Low Hydro-Base Case* Scenario").

(1) Fourth National Power Plan: 1997-2012, Government of India, Central Electricity Authority, March 1997.
(2) Electricity Supply Industry, Salient Data (1994-1995), Central Electricity Authority, October 1996.

3. For the thermal component, historical data is used for 1993/94 and 1994/95. The incremental increase in energy demand in subsequent years (less the hydro and nuclear components) is then split between gas (both natural and liquefied), imported coal, domestic coal and naphtha in the proportions calculated in the Case Studies for Bihar and Andhra Pradesh. The results from Bihar are applied to the eastern and north-eastern regions and the results for Andhra Pradesh are applied to the northern, western and southern regions.

The development of the fuel consumption on the power system resulting from these assumptions is shown in *Figure 2.4*. Although the analysis is based on the Low Hydro case, it is noticeable that the hydro capacity increases strongly. Given the strong opposition to many hydro developments this may not be achieved. In this case the discrepancy will be made up by thermal power and emissions will increase proportionately.

Figure 2.4 Electricity Generation by Fuel (TWh)



It has already been noted that the growth in hydro power is high, even under the CEA's Low Hydro Base Case. The CEA also produced a High Hydro Base Case and this has also been analysed within the EM model. A comparison of the High Hydro and Low Hydro cases is shown in *Table 2.17*.

In 2014/15, supply from hydro plants under the High Hydro Base Case is 365.6 TWh, just 13.6 TWh (4%) higher than under Low Hydro; the principal difference is in the timing of investment; in 2001/2, supply from hydro plant under High Hydro is 156.0 TWh compared to 119.8 TWh under Low Hydro. These figures correspond to installed capacities of 15,919 MWe and 10,621 MWe respectively. The earlier investment in hydro under High Hydro, delays investments in, principally, coal-fired plants until later in the projection period, and therefore delays also the coal based air pollution.

Table 2.17 Electricity Demand for all India Split by Generation Source (TWh)

Year	Hydro	Coal-Imp	Coal-Dom	Gas	Naphtha	Nuclear	Total
Business as Usual Scenario							
(*Low Hydro Base Case*)							
1993/94	70.5	0	233.2	14.7	0	5.4	323.7
1996/97	87.2	0	289.1	51.7	0	5.6	433.6
2001/02	119.8	0	428.1	68.1	28.5	10.0	654.5
2006/07	190.1	0	540.6	95.3	33.0	39.4	898.4
2011/12	291.3	6.2	742.1	95.5	41.7	39.4	1216.3
2014/15	352.0	72.1	797.9	115.5	29.9	39.4	1407.0
Business as Usual Scenario							
(*High Hydro Base Case*)							
1993/94	70.5	0	233.2	14.7	0	5.4	323.7
1996/97	87.2	0	289.1	51.7	0	5.6	433.6
2001/02	156.0	0	401.5	64.1	22.8	10.0	654.5
2006/07	228.3	0	515.0	93.0	27.7	34.4	898.4
2011/12	314.1	5.6	726.8	93.3	36.8	39.4	1216.3
2014/15	365.6	76.4	786.6	114.8	24.2	39.4	1407.0

The main characteristics of fuels assumed for the modelling are summarised in *Table 2.18*. Although some Indian coals can have lower levels of ash than that shown in the Table, 40% is typical of power station grades. An efficiency of 97.5% was assumed for the ESPs.

Table 2.18 Assumed Characteristics of Indian Fuels

Fuel	Sulphur Content (%)	Ash Content (%)
Domestic Coal	0.5	40.0
Imported Coal	1.5	12.5
Natural Gas/LNG	0.0	0.0
Naphtha	0.5	0.0

The estimates of emissions for all-India are presented in *Table 2.19*, which shows results for both the High and Low Hydro Cases. There are only minor differences in the plant composition by the end of the period so emissions also at the period end are similar. The largest differences occur in 2001/2. In this year, the extra hydro generation, results in decreases in emissions of 28 Mt CO_2, (773 g/kWh saving per extra unit of electricity generated by hydro), 170 kt SO_2 (4.7 g/kWh), 120 kt NOx (3.3 g/kWh), 160 kt of particulates (4.4 g/kWh) and 6 Mt Ash (166 g/kWh).

Table 2.19 Emission Calculations for "All India"

Year	CO2 (million tonnes)	SO2 (k tonnes)	NOx (k tonnes)	Particulates (k tonnes)	Ash (million tonnes)
Low Hydro Base Case					
1993/94	198	1,300	906	1,340	52
1996/97	245	1,620	1,130	1,660	65
2001/02	392	2,520	1,760	2,480	96
2006/07	493	3,180	2,220	3,130	122
2011/12	679	4,410	3,060	4,300	167
2014/15	775	5,380	3,500	4,690	183
Cumulative	10,069	-	-	-	2,487
High Hydro Base Case					
1993/94	198	1,300	906	1,340	52
1996/97	245	1,620	1,130	1,660	65
2001/02	364	2,350	1,640	2,320	90
2006/07	466	3,020	2,100	2,980	116
2011/12	660	4,300	2,980	4,210	164
2014/15	763	5,340	3,460	4,630	180
Cumulative	9,709	-	-	-	2,422

The distribution of emissions by region under the BAU scenario (Low Hydro Base Case) in 2014/15 is shown in *Figure 2.5*. The Western region is the biggest emitter, being responsible for 36% of emissions. The Northern region is the next largest with 28%, with the Southern region being responsible for 20% and the Eastern/North-Eastern Region accounting for just 15%.

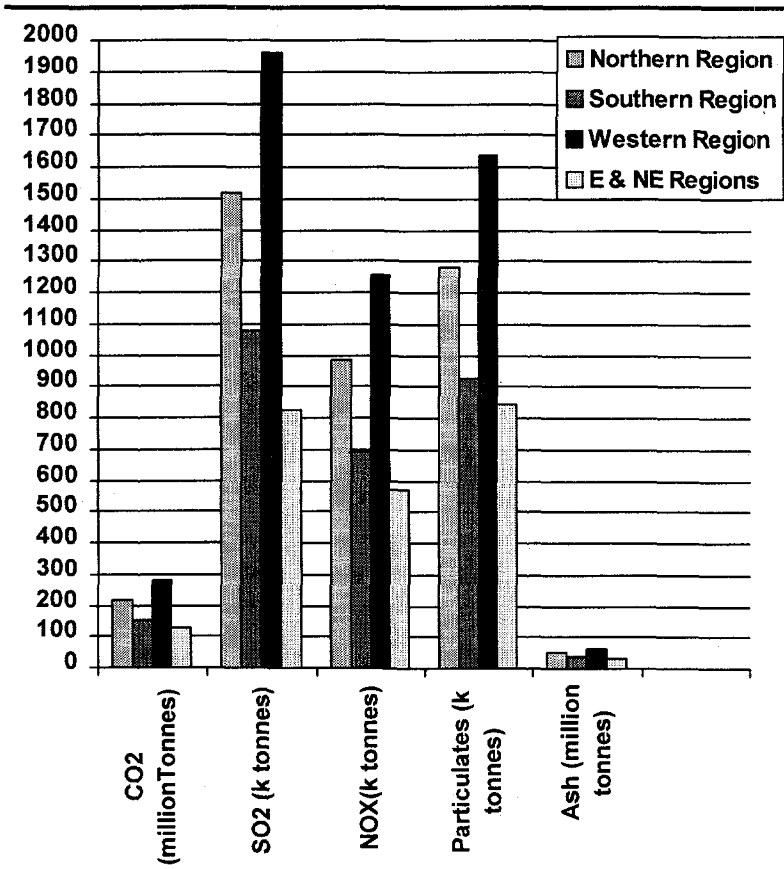
Inevitably, the impacts of the power sector on the environment will increase along with the activity of the power sector. By 2014/5 the power sector in India could be producing some 775 million tonnes of carbon dioxide a year. This may be compared to the roughly 1,000 million tonnes presently produced by power generation in the European Union.

The results also suggest that by 2015 over 183 million tonnes of ash will be produced by the power sector every year (cumulatively this is approximately 2.5 billion tonnes from 1993/94 to 2014/15). To dispose of this ash will require over 1,000 km^2 of land, assuming that 0.81 hectares of land is required per MW of installed capacity [(1)]. This is

(1) Source: Coal Ash Management in Thermal Power Plants: Ash Management, Disposal and Utilisation Study Component. Prepared for the World Bank by Water and Earth Science Associates, August 1996.

of the order of one square metre per person. Increased use of imported coal, which has a significantly lower ash content, would help mitigate the problems.
Emissions of sulphur dioxide will rise to over 5 million tonnes per year by 2015, more than four times the emissions in 1993 (an annual increase of 7% per annum). For comparison, 6 million tonnes were produced in power generation in the EU in 1995, but the amount is forecast to fall to 4.5 million tonnes in 2000 and to decrease rapidly thereafter. In the US emissions peaked at about 16 million tonnes in 1975 and have been falling fairly slowly since. In India emissions of sulphur will be rising in the study period; in Europe and North America they will be falling.

Figure 2.5 "All India" Emissions by Region in 2015



Assuming an Indian population of 1,250 million in 2015, SO_2 emissions are projected to be 4.3 kg/capita under BAU in 2015. This compares favourably with the present EU figure of 16 kg/capita, but this is expected to decrease rapidly in the medium term. Comparing figures by electricity generated, India's projected emissions of 5,380 kt SO_2 while generating a total of 1407 TWh result in specific SO_2 emissions of 3.8 g/kWh electricity generated. By comparison, the EU's present generation of 2300 TWh results in specific SO_2 emissions of 2.6 g/kWh electricity generated and, again, this figure is projected to decrease rapidly in the future. However, it should be noted that the EU has a substantial share of natural gas in its fuel mix.

The RAINS-Asia model (1) contains projections for SO_2 emissions from India from all sectors of the economy (i.e. including transport, etc.). Although separate projections of energy related emissions are made during the modelling process, they are not reported separately. *Table 2.20* shows the projections of SO_2 from all sources. SO_2 emissions in 1990 were estimated at 4,471 ktonnes, i.e. 3-4 times the figure in the BAU scenario for "All India". The rates of increase of SO_2 emissions are dependent on the assumption about future installation of control measures, and range between 0.9% per annum if Best Available Technologies are fitted to all technologies through to 4.9% per annum for the Business as Usual scenario. This rate of increase, although based on different energy projections and a different set of emissions sources, is comparable to the rate of increase derived from the "All India" BAU scenario.

Table 2.20 RAINS-ASIA SO_2 Emissions projections for All India

Year/scenario	SO_2 (k tonnes)	Multiplier re: 1990	Annual Increase (%)
1990	4,471	1.00	-
2020/BAU	18,549	4.15	4.9
2020/Basic Control Technologies	13,054	2.92	3.6
2020/Advanced Control Technologies	10,522	2.35	2.9
2020/Advanced Control Technologies only installed in polluted areas	13,434	3.00	3.7
2020/BAT	5,906	1.32	0.9

Emissions of oxides of nitrogen will be 3.5 million tonnes at the end of the period. In the EU in 1995, production of NOx from the power sector is estimated to have been a little less than 2 million tonnes; it is expected to fall steadily in the future. In the US emissions are some 6-7 million tonnes per year.

Ground level concentrations of sulphur and oxides of nitrogen in India will also be affected by the increase in total emissions. Given that the increase in volume will also be associated by an increase in sites this may not be a crucial issue, except in specific locations. The issue is discussed in more detail in later sections.

Emissions of particulates increase along with the general trend. Given that exposure to particulates is already high in India this increase may be difficult to manage. On the

(1) Source: RAINS-ASIA: An Assessment Model for Air Pollution in Asia. Final Report for the World Bank Sponsored Project "Acid Rain and Emission Reductions in Asia". December 1995.

other hand the exposure arising from the power sector is already low in most cases and there is scope for more efficient controls and better maintenance. With the proper policies this may also be manageable. The consequences are discussed in more detail in later sections.

2.1.6 *Comparisons With Other Work*

The Canadian Energy Research Institute (CERI) in conjunction with the Tata Energy Research Institute investigated the analysis of Indian emissions through to 2016. (1) A comparison with the EM analysis is given in *Table 2.21.*

Table 2.21 Comparison of EM and CERI Calculations

	CO2 (million tonnes)	SO2 (k tonnes)	NOx (k tonnes)	Particulates (k tonnes)
EM - 2014/15 (BAU)	775	5,380	3,500	4,690
CERI - 2016	902	5,020	4,771	5,139

Source: Canadian Energy Research Institute and Tata Energy Research Institute: Planning for the Indian Power Sector - Environmental and Development Considerations. Study No. 62, June 1995.

The major difference between the projections is for CO_2, where the EM model projects emissions to be 14% lower than the CERI study. The demand forecasts on which the two studies are based are similar. If the plant efficiencies and fuel emissions factors used in the EM model are applied to the fuel demands for electricity generation projected in the CERI study, then there is good agreement in the projected CO_2 results. The different forecasts arise from different assumptions about fuel quality and composition.

The estimates of the emissions of oxides of sulphur and particulates are as close as can be expected given the inherent uncertainties in the analysis.

There are large discrepancies between the estimates of emissions of NOx. Calculations of NOx are sensitive to the technical assumptions made. The results for NOx should therefore be treated with a certain degree of caution. NOx emissions depend on the efficiency of combustion and the combustion technology used. The CERI study may assume that Indian boilers run at a higher air to fuel ratio than is desirable and this will contribute towards higher energy losses and emissions in the flue gases.

(1) Canadian Energy Institute, Tata Energy Research Institute , Planning for the Indian Power Sector, 1995

2.2 *WOULD REFORM AND RESTRUCTURING OF THE POWER SECTOR BENEFIT THE ENVIRONMENT?*

The power sector throughout India is changing. The high voltage transmission system has already been separated from generation and the State Electricity Boards are moving slowly towards reform. It is important to assess the implications for the environment.

This section does not look at institutional and managerial aspects of Reform, nor at questions of ownership. It is confined exclusively to the kinds of technical changes which will be associated with reform. It looks especially at the consequences of the different price structures that can be expected and the higher technical efficiency.

There are four subsidiary questions:

- how much will demand for electricity be affected and how will this affect the environment?
- how will choice of fuel be affected?
- will reform have a significant effect on the ability of companies to finance environmental expenditures?
- what would be the welfare consequences of reform?

2.2.1 *The Reform Scenario*

The Reform scenario assumes that reform of the electricity sector is accompanied by reform of the economy as a whole, with a consequent increase in the rate of growth of the state domestic product and therefore of the demand for electricity. Change of the tariff structure to reflect the economic costs of production means higher prices for electricity in the residential and agricultural sectors that will dampen demand.

Reform of the wider energy sector is envisaged to bring the prices for power station fuels into line with the economic costs. This process is underway. Most coal prices have now been deregulated except for some grades that are used for power production. Power station grades of domestic coal are priced below the cost of production and the different prices for the different grades of coal underestimate the true value of the better grades. Prices for the transport of goods by rail are generally subsidised, including those for coal.

These distortions in prices can effect the environment. Indian coal will be unduly preferred as a fuel for power generation over other fuels with lower ash content; the relative prices of different grades of coal give no incentive to the coal producer to increase output of the better quality coals; distorted prices for transport distort the choice between pit-head rather than load-centre plants and shift the location of the environmental impacts.

The electricity sector is assumed to operate with commercial motives and has an adequate cash flow; it therefore invests to rehabilitate transmission and distribution and to modernise generating plant. Transmission and distribution losses fall and plant that does not comply with the environmental standards is brought into compliance.

The improved reliability of the power system means that consumers no longer have the same incentive as now to install their own supplies. That part of captive generation that is more appropriately supplied from the grid, is progressively eliminated.

2.2.2 *The Evidence from Andhra Pradesh*

The Economic Costs of Fuel

The economic costs, of coal in Andhra Pradesh have been calculated on a mine-by-mine basis using long-run marginal cost principles. The coal fields of Talcher and Ib Valley in Orissa have large reserves of power station grade coal. Coal from Talcher has the lower cost so the marginal production cost from the area is set by Ib Valley. This is estimated to be about 540 Rs/tonne. The long-run marginal cost of production from Singareni is estimated at 896 Rs/tonne; it is assumed that the output cannot be directly substituted at the Singareni pit-head by coal from Orissa because of the high cost of transport. Adjustments for transport and losses are made to these economic costs at the mine mouth. The economic cost of delivered coal to the various existing and candidate power plants are then estimated as shown in *Table 2.22.* This shows Talcher pithead to offer the lowest cost coal. However, after correction for the cost of electricity transmission to AP, it becomes more expensive than electricity generated using Singareni coal in AP. Economic costs for other fuels are taken from the Special Study on Interfuel Substitution. For comparison the financial costs used in the BAU scenario are also shown in the Table.

Using economic costs improves the position of Talcher coal relative to that from Singareni; the change has little influence on the choice of pit head and load centre sites despite the significant differences in transport costs in the two cases. Imported coal and natural gas become more competitive, especially when allowing for the high conversion efficiency of natural gas in power generation.

Table 2.22 Economic and Financial Costs of Fuels (Reform)

	Cost of Coal (Rs/t)	Cost of Transport (Rs/t)	Total (Rs/t)	Gross of Loss (Rs/t)	Economic Fuel Cost (Rs/MMBtu)	Financial Fuel Cost (Rs/MMBtu)
Existing & Committed						
VTPS - Tal'	540	500	1040	1248	94.3	86.3
KTPS - Sing'	896	171	1067	1280	97.8	57.5
RTPP - Sing'	896	411	1307	1568	119.0	90.0
Vizag - Tal'	540	330	870	1044	79.7	63.8
Future coal						
Talcher PH	540	90	630	756	57.7	37.6
Sing' PH	896	90	986	1183	90.4	54.1
Talcher LC	540	522	1062	1274	97.3	86.2
Sing' LC	896	248	1144	1373	104.8	72.9
Other Fuels						
Imp'd Coal	1940	443	2383	2621	100.1	101.4
Naphtha	7960		7960	7960	182.4	154.1
Local gas					92.8	79.1
LNG					136.5	136.5

Source: Andhra Pradesh Case Study, ASCI Consultancy, 1998.

The Candidate Plants

The candidate plants remain the same as for the BAU option, but the capital costs are changed to reflect economic rather than financial costs. Economic costs were estimated by removing taxes and subsidies. No adjustment has been made for a foreign exchange premium because the value of the Rupee is close to the real exchange rate. *Table 2.23* compares the economic costs to the financial costs used in the BAU scenario. Port costs for imported coal are included as a part of the fuel cost.

Table 2.23 Financial and Economic Costs of Candidate Plants

	Capacity (MW)	Financial Capital Cost (kRs/kW)	Economic Capital Cost (kRs/kW)
Singareni (pit head)	500	40	33.3
Talcher (pit head)	500	64	57.3
Singareni (load centre)	250	43	35.8
Talcher (load centre)	250	43	35.8
Imported Coal (coastal)	250	43	35.8
Naphtha	400	35	29.2
Gas based CCGT	116	32	26.7
LNG	232	32	26.7
Hydro	110	35	29.2

Source: Andhra Pradesh Case Study, ASCI Consultancy, 1998.

Demand and Losses

There are contradictory influences on final demand from the higher efficiency of electricity use as a consequence of higher prices and the higher level of economic activity as a consequence of reform. The market shares of the different sectors are assumed to change differently from BAU to Reform and this influence on demand is modelled through the different energy intensities.

The price elasticities are assumed the same as for BAU, but the tariffs increase significantly. The Reform scenario assumes that the price of electricity to all consumer sectors should reflect long run marginal cost. This implies large price increases to domestic and agricultural consumers. The main part of the price rises are effected in less than 5 years. The tariffs that underlie the forecast are given in *Table 2.24*. Complete adjustment to long run marginal cost has still not been entirely achieved for agriculture. The evolution of demand at the bus-bar is compared for the Reform and BAU scenarios in *Table 2.25*.

Table 2.24 Sectoral Tariffs for the Reform Scenario (Rs/kWh)

	Industry	Commerce	Domestic	Agric'l
96	3.00	3.00	1.65	0.06
96/97	3.00	3.00	1.82	0.06
97/98	3.00	3.00	2.18	0.12
98/99	3.00	3.30	2.61	0.36
99/00	3.00	3.30	3.40	1.08
00/01	3.00	3.30	3.91	2.48
01/02	3.00	3.30	4,10	2.73
02-07	3.00	3.63	4.10	2.73
08-11	3.00	4.00	4.31	3.01
12-15	3.00	4.00	4.50	3.25

Source: Andhra Pradesh Case Study, ASCI Consultancy, 1998.

Table 2.25 Demand Under the BAU and Reform Scenarios (TWh)

Year	1996/97	2001/02		2006/07		2011/12		2014/15	
		Reforms	BAU	Reforms	BAU	Reforms	BAU	Reforms	BAU
Industry	11.3	19.2	16.8	30.6	25.1	48.8	37.6	64.6	47.9
Commercial	1.2	1.9	1.8	3.3	2.6	5.5	4.0	7.4	5.0
Domestic	4.7	5.6	6.7	9.0	10.0	14.4	14.9	19.2	19.0
Agriculture	14.1	12.0	16.0	15.6	23.9	20.2	35.9	23.4	45.8
Losses	6.3	6.2	7.2	7.0	9.2	8.9	13.9	11.5	17.7
Total	37.6	45	48.4	65.7	70.9	98.4	106.2	126.9	135.3
Peak (MW)	6340	7321	7867	10320	11132	14935	16120	18892	20144

Source: Andhra Pradesh Case Study, ASCI Consultancy, 1998.

Industry has a larger share of demand under the Reform Scenario than under BAU; its share reaches 56% by 2014/15. The growth is largely at the expense of agriculture and this reflects the impact of economic pricing to agriculture.

Technical and non-technical losses are assumed to reduce from 19% in BAU to 10% by 2010. These improvements arise because of the commercial motivation that leads to improved maintenance, metering, monitoring, billing and collection and the availability of more money for these purposes. The countries of the Asian Development Bank region in 1990 had average T&D losses of 16.5%, with a large variation between countries.[1] The best performers were Singapore (9.1%) and the Republic of Korea

(1) Asian Development Bank, Electric Utilities Data Book, Manila, 1993.

(10.2%), with China having an average for the Six Networks of 12.9%. Given appropriate actions, India should be able to match these figures by the end of the period (2014/15).

In summary:

- the efficiency of end use improves so demand growth is lower; and
- T&D losses are reduced so further lowering demand.

The Expansion Plan and Generation by Fuel

The main effects on the expansion plan are:

- reduced demand rolls back all plant additions;
- the higher prices for domestic coal cause the Singareni coal to be backed out; coal from Talcher is still cheap enough to be the preferred fuel;
- reduced demand lowers the requirement for imported coal.

The fuel-burn at the beginning and end of the period under BAU and Reform is shown in *Table 2.26.* The large consumption of naphtha arises from the IPPs that are assumed committed at the beginning of the period.

Table 2.26 Electricity by Fuel Compared in the BAU and Reform Scenarios (TWh).

	Talcher Coal	Coal from AP	Local Gas	Naphtha	Hydro	Coal Imports	LNG	Total
1996/7	8.1	14	1.7		9.4			33
BAU 2014/5	57	32	4.9	5.7	9.6	19	7.9	135
Reform 2014/5	59	23	5.2	4.3	9.6	20.5	5.8	127

Source: Andhra Pradesh Case Study, ASCI Consultancy, 1998.

The evolution of the reliability of the system is shown in *Table 2.27.* Again, the rapid improvement in reliability is a function of the assumptions made about the successful construction of plants thought to be committed.

Table 2.27 *System Reliability*

Year	1996/97	2001/02	2006/07	2011/12	2014/15
Reserve Margin (%)		9.2	11.1	8.7	11.1
Unserved Energy (GWh)	4597	42	41	96	69
LOLP (%)	71.9	2.5	1.6	1.5	1.3

Source: Andhra Pradesh Case Study, ASCI Consultancy, 1998.

Environmental Attributes

Emissions under the Reform Scenario are summarised in *Table 2.28.* The attributes are all reduced by between 6 and 10%. The effect of Reforms is therefore favourable for all attributes over the period under consideration.

Table 2.28 *Summary of Emissions under the Reform Scenario*

Year	Cumulative CO_2 mt	pv of NOx kt	pv of SOx kt	pv of TSP kt	Cumulative Ash mt
BAU	1240	2550	2497	251	254
Reform	1138	2390	2363	233	226

Source: Andhra Pradesh Case Study, ASCI Consultancy, 1998.

Financial Implications

The average incremental cost of bulk supply and the average delivered cost are compared to BAU in *Table 2.29.* The costs in the BAU scenario (using financial prices) are higher than in the Reform scenario (using economic prices) even though the costs of coal are higher in economic terms. This arises because the fuel costs of the IPPs are expressed in BAU in terms of the contracted price, which is higher than the economic price.

Table 2.29 *Costs of Supply*

	Average Incremental Cost of Bulk Supply (Rs/kWh)	Average Incremental Delivered Cost (Rs/kWh)
BAU	1.77	2.02
Reforms	1.46	1.65

Source: Andhra Pradesh Case Study, ASCI Consultancy, 1998.

The financial performance under Reforms is much improved compared to BAU. The average incremental costs under Reform are higher than for BAU because the high contracted prices for output are used in BAU. The calculated rate of return for selected years is summarised in *Table 2.30.*

Table 2.30 Rate of Return on Capital Employed for Selected Years (%)

Year	Return (Reform)	Return (BAU)
1996/7	5.7	3.6
2001/2	25.9	-7.2
2006/7	12.0	-6.8
2011/2	7.4	-15.6
2014/5	4.6	-127.7

Source: Andhra Pradesh Case Study, ASCI Consultancy, 1998.

The high rate of return in the early years arises because electricity otherwise given to agriculture at a loss, is sold to industry at a profit. At present industry is preferentially disconnected when supplies are low and those profits are lost. If the IPPs that are committed are built, then a substantial increase in revenue can be achieved by APSEB without capital outlay, by selling on the power from the IPPs to the industrial market.

The financial results are a first trial. In subsequent iterations the tariffs should be reduced in the period around 2001/2 to bring the return down and raised towards the end of the period to bring the return up. The calculations allow for a real increase in fuel prices, but no real increase in electricity prices once the economic tariff levels have been achieved. The need for this fine tuning is evident, but does not detract from the general impression of a viable business.

2.2.3 The Evidence from Bihar

The Economic Cost of Fuels

Fossil fuel options available to power plants in Bihar and to plants outside Bihar that could supply BSEB, include:

- coal mined in Bihar;
- coal from Talcher in pit head plants supplying BSEB;
- imported coal burnt in coastal sites supplying BSEB;
- LNG to coastal sites; and
- natural gas from Bangladesh.

Bihar has abundant reserves of poor quality steam coal. It is a land-locked state and the coal fields are 400 km from the nearest port. The IFS Special Study estimates the marginal production cost from coal fields in Bihar to be 580 Rs/tonne, irrespective of grade.

The better grades of power station coal (D, E and to a lesser extent F) are currently scarce relative to demand. Grade G is abundant. It is therefore appropriate to take the cost of production of Grade G coal as a reference and to calculate opportunity costs for the other coal by reference to appropriate price differentials.

The reserves at Talcher and in the Ib valley are larger than those in Bihar and have lower marginal costs of production. The cost of transport to Bihar exceeds the difference in production cost. The coal mines in Bihar are therefore protected both from lower cost coal in Talcher and from abroad. It may still be economic to build plant either at Talcher or on the coast and to import electricity. This possibility is investigated in the Case Study.

The cif border price for LNG has been calculated on the basis of tenders recently submitted by international oil companies in response to an invitation from the GAIL. In the absence of any other information, the same price was used in the Case Study for piped gas from Bangladesh. The economic and financial costs of fuel, as of March 1997, are summarised in *Table 2.31.*

Table 2.31 Economic and Financial Costs of Fuel in Bihar

	Economic Cost	Financial Cost
Domestic Coal (Rs/t)		
D grade	1350	524
E grade	1090	420
F grade	815	339
G grade	580	247
Imported Coal	c.i.f. border price	plus import duty
	1800	2000
LNG/piped gas (Rs/MMBTU)	c.i.f. border price	
	157.5	157.5

Source: Bihar Case Study, SCADA, 1998.

Rehabilitation, Committed and Candidate Plants

Because of the improved cash flow, all of the BSEB plants are assumed to be rehabilitated with emergency, medium and long-term measures implemented. The financial constraints on purchase of power by BSEB are eased and therefore the power purchases from NTPC and TVNL are gradually realised to the full level of the entitlement. The committed plants described within the BAU scenario are also included within the Reform scenario.

The set of candidate plants considered in the system expansion includes:

- construction of new plants on existing sites;
- development of green-field sites in Bihar;
- in-state hydro projects including pumped-storage;
- purchase of power from new plants on the Talcher coalfield;
- plants in coastal locations burning LNG or imported coal; and
- plants burning piped natural gas from Bangladesh.

The candidate plants considered in the expansion reflect the variety of fossil fuel choice described in the previous section plus some hydro options. The pertinent data is given in *Table* 2.32. Only economic prices are given; financial prices would be 17 - 18% higher in each case, because of taxes.

Demand and Losses

The initial estimate of electricity prices in the Reform scenario assumes that prices converge on long run marginal costs by 2001/2. The estimates of marginal cost were taken from studies carried out in other states including Utter Pradesh and Haryana). These estimates were used to drive the demand model, an expansion plan was derived, the financial implications were modelled and then the price levels revised to achieve an appropriate financial performance. The assumptions regarding price and income elasticities, and the tariffs for sale to different sectors are given in *Table* 2.33. Comparison with BAU shows a large increase across the board by 2015 and especially in agriculture. Nevertheless, by 2015 it is still assumed that agricultural prices are below costs.

Table 2.32 ***Principal Candidate Plants for Bihar***

	Fuel	Capacity (MW)	Heat Rate (BTU/kWh)	Economic Cost (kRs/kW)
Fossil fuel				
Katihar-210	Local Coal	195	10352	35.3
Talcher II	Talcher Coal	195	10160	42.3
Tenughat 210-Ext.	Local Coal	195	10352	28.9
Nabinagar	Local Coal	195	10160	41.1
Muzzaffarpur-Ext	Local Coal	195	10352	28.9
Chandil 210	Local Coal	195	10352	35.3
Tenughat 500-Ext.	Local Coal	195	10160	41.1
Bangladesh gas	(up to 4 units)	195	7799	23.4
LNG	(up to 4 units)	195	7799	24.3
Imported Coal		195	9970	45.7
Hydro				
Kadwan		450	2783 GWh/yr	23.4
Sankh-II		186	858 GWh/yr	40.4
Koel-Karo		710	1058 GWh/yr	37.1
Storage Hydro		300		35.9
Renewables				
Biomass		9.5	12342	32
Bagasse cogen		190	12342	25

Source: Bihar Case Study, SCADA, 1998.

Table 2.33 ***Sales Tariffs in Reform***

	1996	1997	1998	1999	2000	2001-15
Residential	1.42	1.84	2.39	3.09	4.01	5.20
Commercial	1.75	2.11	2.54	3.06	3.68	4.44
LT Industrial	2.33	2.47	2.61	2.77	2.93	3.10
HT Industrial	2.27	2.40	2.54	2.69	2.85	3.02
Agriculture	0.25	0.42	0.71	1.18	1.99	3.33
Street lighting	1.70	2.06	2.49	3.02	3.66	4.44
Other	2.15	2.30	2.47	2.66	2.85	3.06

Source: Bihar Case Study, SCADA, 1998.

The rate of growth of SDP is also assumed to be substantially higher in the Reform case than in BAU. The rates of growth in SDP itself are summarised in *Table* 2.34. There are also differential rates of growth assumed for each sector.

Table 2.34 ***Average Rates of Growth of SDP in BAU and Reform***

	1996-2002	2003-2007	2008-2015
BAU	3.50	3.75	4.50
Reform	4.50	5.70	6.00

Source: Bihar Case Study, SCADA, 1998.

The price and income elasticities used in the demand forecast are the same as for BAU, with the exception of that for agriculture which is assumed to increase in magnitude with time as behaviour becomes more responsive to higher prices. The variation is as shown in *Table 2.35.*

Table 2.35 ***Price Elasticity for Agriculture***

	1996	1997	1998	1999	2000	2001-15
Price elasticity	0	-0.1	-0.2	-0.3	-0.4	-0.5

Source: Bihar Case Study, SCADA, 1998.

A comparison of the demand forecasts under BAU and Reform is given in *Table 2.36.*

Table 2.36 ***Demand Under the BAU and Reform Scenarios (GWh)***

Year	1995/96	2001/02		2006/07		2011/12		2014/15	
		Reforms	BAU	Reforms	BAU	Reforms	BAU	Reforms	BAU
Residential	726	819	1072	1418	1316	2325	1499	3190	2325
Commercial	418	600	674	952	829	1482	914	1963	1482
LT Industry	202	579	518	917	628	1463	685	1967	1463
HT Industry	1973	4758	4253	7517	5156	11998	5616	16133	11998
Agriculture	1365	604	1296	902	1330	1188	1255	1425	1188
Street Lighting	28	30	28	34	28	37	24	40	37
Others	675	868	795	1164	938	1530	959	1831	1530
Total	5387	8258	8636	12904	10225	20023	10952	26549	20023

Source: Bihar Case Study, SCADA, 1998.

The comparison of demand in the two scenarios is interesting. Initially the sectors suffering high price rises such as agriculture and the residential consumers show a significant fall off in demand while the industrial sector is less affected by price rises and the effect of the stimulated economy is predominant. The stronger economy begins to be the dominant influence on the residential sector by about 2006, although agricultural demand is still lower than in BAU. By 2011 agricultural demand has almost recovered and by the end of the period all sectoral demands are higher under Reform than in BAU.

Technical losses of electricity are assumed to fall from 28% in 1997 to 18% by 2004 as a result of rehabilitation and improved maintenance. Non-technical losses fall from 9% in 1997 to 4% in 2004 because of improved metering, billing and collection. The assumptions are summarised in *Table 2.37.*

Table 2.37 Losses in the Reform Scenario (%)

	1996	2005-2015
Residential		
Technical	28.9	16.9
Non-Technical	14.3	8.3
Commercial		
Technical	28.9	16.9
Non-Technical	5.3	3.1
LT Industrial		
Technical	28.9	16.9
Non-Technical	1.6	0.9
HT Industrial		
Technical	14.5	8.8
Non-Technical	1.1	0.6
Agriculture		
Technical	33.3	20.0
Non-Technical	20.1	11.7
Street Lighting		
Technical	28.9	16.9
Overall		
Technical	27.6	18.6
Non-Technical	8.9	4.0

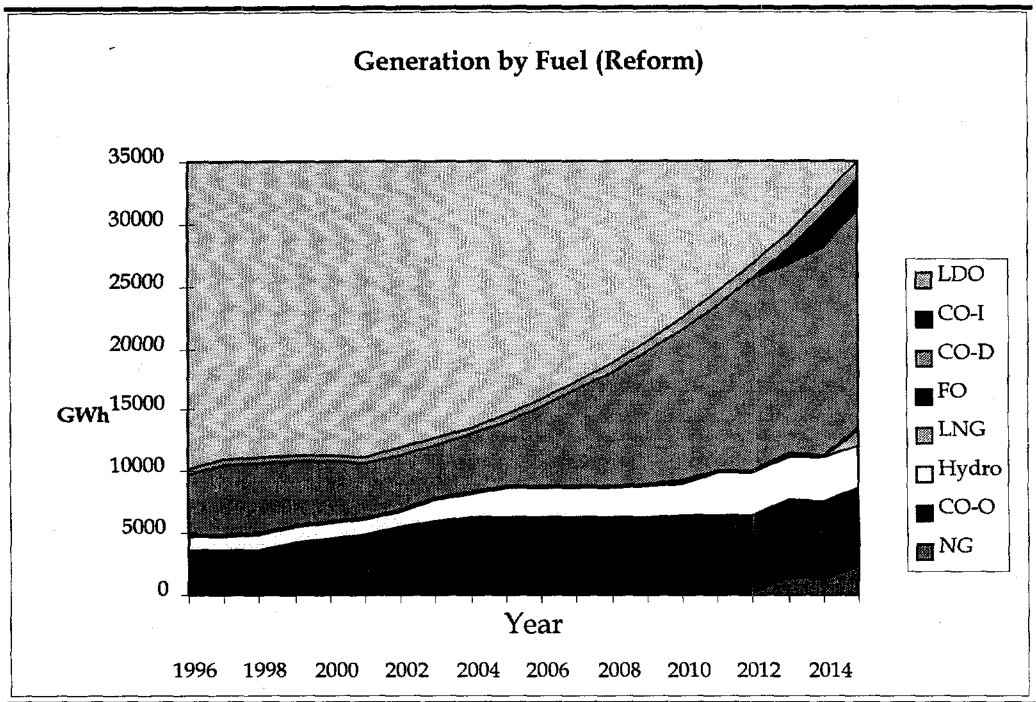
Source: Bihar Case Study, SCADA, 1998.

The Expansion Plan

The combination of the rehabilitation of existing plant, the reduction in technical losses and the reduced demand, plus the ability of BSEB to draw on its full entitlements from NTPC mean that the system LOLP falls steadily from 40% in 1997 to about 5% in 2001 and remains around that level throughout the period. No new plant is needed before 2005.

Over the period, the expansion plan selects all the hydro plants, except the pumped storage unit. Natural gas is selected, both piped from Bangladesh and imported as LNG. This is because the availability of gas from Bangladesh is constrained to be sufficient to supply 4 x 200 MW units; if more were available it would be preferable to LNG. Talcher is chosen only at the very end of the expansion plan and its generation is not visible in the Figure. Only one new coal-fired plant is built in Bihar. The generation by fuel is shown in *Figure 2.6.* CO-I in the legend refers to imported coal. The greater diversity than in BAU is noticeable(see *Figure 2.2)*, but the reliance on domestic coal is still striking. Of the incremental capacity one third is from natural gas.

Figure 2.6 ***Generation by Fuel in Reform Scenario (Bihar)***



Source: Drawn from the results of the Bihar Case Study, SCADA, 1998.

Environmental Impacts

The environmental consequences of reform are determined by a balance of the effects of reform on demand for, and the supply of, electricity. As described above, the impact of reform on unconstrained demand depends on the relative strength of the price effect (dampening demand) and income effect (raising demand). In Bihar the income effect becomes dominant around the year 2002/3 leading to higher demand under reform. However, reform also improves utilities' cash flow which has important environmental benefits. The main effect, as noted above, is that more plant can be built which will therefore increase the volume of environmental impacts. A second effect is that the improved cash flow allows investments to be made to bring existing plant into compliance with standards. A third point is that the new plant built in reform are intrinsically cleaner and more efficient and they tend to displace old plant down the merit order. The second and third points act to bring down the specific emissions of pollutants.

The consequences are summarised in *Table 2.38* and clearly show that all environmental attributes are lower under reform than BAU indicating that the beneficial aspects of reform dominate.

Table 2.38 Summary of Emissions under the Reform Scenario

Year	Cumulative CO_2 mt	pv of Nox kt	pv of Sox kt	pv of TSP kt	pv of Ash mt
BAU	142	804	929	62	36
Reform	127	685	828	54	34

Source: Bihar Case Study, SCADA, 1998.

Financial Implications

The financial consequences of reform are dramatic. Some financial indicators for the BAU and Reform scenarios are compared in *Table 2.39.* The average incremental cost of supply in reform is now substantially lower than unit revenue and this appears in the favourable rate of return on assets and the debt service ratio.

2.2.4 *Comparison with Other Studies*

We have found no other quantitative work that discusses the environmental impacts of reform.

2.2.5 *Welfare Implications of Reform*

A review of the literature on welfare impacts of policy changes in the energy sector was undertaken as one of the Special Studies. (1) The study considered five areas where reform might have a detrimental impact on welfare:

- electricity prices to residential consumers;
- the level of electricity prices to agriculture;
- the abandonment of flat rate tariffs;
- employment in the coal industry, and
- use of fuel wood by households.

(1) ERM India, Welfare Effects of Policy Changes: A Special Study, 1997

Table 2.39 Financial Indicators for BAU and Reform

	BAU	Reform
Cost of generation (Rs/kWh)	1.31	1.84
Cost of sales (Rs/kWh)	1.91	2.27
Unit revenue (Rs/kWh)	1.83	3.30
Rate of Return	-14%	12.2%
Debt service ratio	-0.6	3.9

Source: Bihar Case Study, SCADA, 1998.

The review is summarised below.

Electricity Prices and Residential Consumers

More than 70% of households in India are in rural areas and, of these, the majority (67% to 69% from different sources) do not have access to electricity and will be unaffected by electricity price changes. Of the approximately 30% of households that are in urban areas, a much larger proportion (76%) have access to electricity.

The data on household expenditure on electricity have a number of gaps and deficiencies. Rural data are old and unreliable.

Data on urban household electricity consumption are provided in TEDDY, 1996/97. (1) These can be used in combination with published electricity tariffs to estimate expenditure. The results are unreliable to the extent that much of the electricity supply to households is un-metered or partially metered. Without any adjustment for un-metered consumption, the data shows that urban households spend an average of 4.5% of their total expenditure on electricity. Different income ranges spend differing shares but, except for households in the lowest income group below Rs. 500/month, the variation is not wide. For the lowest income group the expenditure share is shown to be 17%. The data should be treated with some caution.

The TEDDY data are broadly corroborated by a survey of 2,800 households in Hyderabad in 1994. This survey suggests that households further up the income scale tend to spend proportionately less on electricity. The lowest income decile, for example, spends 4.6% on electricity while the highest decile spends 2.4%.

The data suggest that for those households with access to electricity any substantial increase in electricity prices could lead to a substantially higher share of expenditure on electricity. In urban areas, for example, a doubling of electricity prices without any reduction in consumption levels could result in a further 5% of household expenditure

(1) Tata Energy Research Institute, TERI Energy Data Directory & Yearbook, 1996/97

being taken in electricity charges. Reforms will normally improve the cash-flow of electricity companies and enable them to penetrate new areas. Consumers not presently connected to the grid may therefore be expected to benefit under reforms.

Electricity Prices to Agriculture

The major direct impact of electricity reform on the agricultural sector will arise through the effect of electricity tariff increases on irrigation. Following the 'Green Revolution' in India, a third of cultivated land is irrigated and in some states, such as Punjab, nearly all of the land is irrigated.

An increase in electricity prices would be expected to lead to:

- a switch in cropping patterns toward crops with lower irrigation requirements; and
- a reduction in irrigated land with consequent reduction in yields.

No empirical studies are available directly estimating the impact of increased electricity prices on irrigation economics and cropping patterns. Additionally, the relationship is distorted by subsidies to fertiliser and seeds and by price control schemes for agricultural produce.

Some evidence is available from micro-level surveys of cropping patterns and irrigation. These surveys consider both irrigation using diesel pumpsets and irrigation using electric pumps. *Table 2.40* shows that the costs of irrigation using diesel pumpsets are generally shown to be twice those using electricity and could be used to indicate the possible impact of a doubling of electricity prices.

Table 2.40 Irrigation Cost as % of Total Input Costs

	Castor	Wheat	Mustard	Bajara	Groundnut
Diesel	26%	36%	24%	48%	14%
Electric	12%	18%	14%	24%	7%

Source: Mohanty and Ebrahim, opus cit.

Two studies described in the Welfare Special Study reported slightly contradictory impacts. One in northern Gujarat showed, contrary to expectations, that farmers using diesel pumpsets tended to irrigate longer and more frequently than farmers with electric pumpsets.(1) The other study showed the reverse;(2) the percentage of the land planted

(1) Kumar and Patel, in Moench Marcus, ed. Electricity Prices: a Tool for Groundwater Management in India; Operations Research Group, Vadodara for the World Bank, 1996.
(2) Mohanty and Ebrahim, in Moench Marcus, ed. Electricity Prices: a Tool for Groundwater Management in India; Operations Research Group, Vadodara for the World Bank, 1996.

to less water intensive crops, such as castor, was only slightly higher in areas without access to electrified pumpsets.

None of the studies described in the Special Study provides firm evidence. The lack of a clear difference in cropping patterns or irrigation in areas with and without access to electricity does tentatively suggest that electricity price changes which bring costs up to the level of diesel pumping would not have a major impact on irrigation or agricultural production. However, this evidence is weak and should be supported by more thorough analysis.

Improved reliability of electricity supply will benefit consumers as there will be less need for private generators, voltage stabilizers and reduced costs associated with disruption of supply.

Abandonment of Flat Rate Tariffs for Agriculture

Another area of concern in the agriculture sector is the consequence of abandoning flat rate tariffs. The argument used to justify the widespread introduction of the flat rate tariff was that there is inequality of access to pump-sets by small farmers and that the introduction of flat rate tariffs would encourage larger landholders to sell water to small farmers.

It is clear that flat rate tariffs have encouraged the increased use of pump-sets and that the sale of water is widely practised. One paper described in the Special Study shows that water charges are uniformly lower in areas which use flat rate electricity prices. Another paper shows that there is significant variation in water charges across the country and that these charges may be more closely related to water scarcity than to the cost of water pumping.

Whether there is inequality of access to pump-sets is also unclear. A survey for Gujarat in 1977, reported in the Special Study, does not suggest any inequality in ownership of pump-sets although anecdotal evidence supports the claim.

The evidence about the impact of abandoning flat rate tariffs on small farmers and agricultural production is again unclear. To provide a definitive assessment, an analysis would need to be undertaken to show the numbers of small farmers dependent on purchased water for their irrigation needs, the impact of a move to unit charges for electricity on water charges and the impact on the economics of irrigation for these small farmers.

Employment in the Coal Industry

Electricity generation in Bihar and Andhra Pradesh using domestic coal from Talcher and Andhra Pradesh is projected to rise from 27 TWh in 1996/7 to 102 TWh in 2014/15 under both the BAU and Reform scenarios. This generation would require 15.3 million tonnes of coal in 1996/7, rising in 2014/15 to 58 million tonnes. The Special Study estimates that for each million tonnes of coal produced an additional 1,134 men would be employed. Thus the expansion in coal demand would lead to an increase in employment in the coal mining sector of 48.4 thousand (ignoring any positive or negative indirect employment impacts).

Fuel Wood

Electricity and fuel wood are not substitutes in India. The NCAER survey, 1985, showed that only one in a thousand rural households and five in a thousand urban households use electricity for cooking. (1) This is supported by the 1997 ESMAP survey for Hyderabad. (2)

Changes in electricity prices or availability will not, therefore, be expected to have a substantial impact on fuel wood use.

2.2.6 *Conclusions*

The effects of reform on the environment in both case studies over the study period are shown to be positive. Price reform decreases demand and therefore the environmental impacts. The stimulated economy increases demand but this effect does not outweigh the other beneficial impacts. More commercial motivation gives incentives to rehabilitate plant and transmission and distribution systems, so reducing losses and improving the environment. The improved cash-flow of companies allows them to comply better with environmental standards. In cases where there is now large suppressed demand, reform is likely to increase environmental impacts. In this work the greater stresses from reform were more evident in Bihar than in Andhra Pradesh.

It should not be forgotten that the higher environmental impacts consequent on increased activity and more reliable supply of electricity arise fundamentally because more electricity is being used. Employment generation and personal and disposable income all increase under reform. These uses will themselves increase welfare and often have local environmental benefits. Examples are the substitution of electric light for kerosene lamps or the avoidance of pollution from small generator sets. These benefits have not been systematically assessed, but they may be significant.

(1) NCAER, Domestic Fuel Survey with Special reference to Kerosene, New Delhi, 1985
(2) UNDP/World Bank, India, Household Energy Strategies for Urban India: the Case of Hydrabad, 1997

2.3 WHAT ARE THE CONSEQUENCES OF CHOOSING PLANT ACCORDING TO ECONOMIC COST?

2.3.1 *The IFS Scenario*

This scenario is described as the Inter-Fuel Substitution (IFS) scenario. It assumes economic costs for all inputs and the same demand forecast as in BAU. It ignores financial constraints to meeting demand, but recognises practical constraints of construction schedules and fuel availability. The main difference between IFS and Reform is therefore in demand.

The principal interest of the scenario is as the first stage of a multi-stage analysis, in which we set a "level playing field" on which to analyse the choice between traditional supply-side options. Subsequently, we consider variations on IFS as a way of testing the impact of specific policies for environmental improvement such as DSM, renewables, T&D rehabilitation.

The scenario poses three subsidiary questions:

- what would be economic prices for domestic and imported fuels?
- what would be the consequences for power system expansion if these prices were used?
- what would be the consequences for the environment?

This section describes first the process of internalising the economic costs, this is a function of the standards, the control technologies and their costs. The section then reports the results of using the total economic costs, including the full economic costs, as the basis for power system planning in the two Case Studies.

2.3.2 *Internalisation of Environmental Costs*

This section explores the consequences of using economic costs for capital and fuel, including the internalisation of the environmental costs. It presents first some generic control costs for coal mining and power plants and shows the implications for the levelised costs of power generation (the equivalent annual cost based on a 12% discount rate). Detailed case studies of specific coal and hydro developments are then presented to show where the environmental and social costs arise and how they are internalised.

Controls on Coal Mining and Power Plants

A Special Study was made as a part of this work to identify the costs of various options for mitigating the environmental impacts of coal mining. Some of the major environmental impacts of open cast mining and the costs of their control are shown in *Table 2.41.*

It should be stressed that such costs may vary from site to site. The costs pertaining to biotic remediation and to resettlement and rehabilitation (R&R) are especially specific to the site. Furthermore there are no fixed standards or guidelines for resettlement and rehabilitation across India and the procedures vary from one State to another. It is assumed that mine back-filling and land reclamation are included in the main project cost.

Table 2.41 Environmental Impacts of Coal Mining and Estimated Costs of Mitigation per tonne of Coal Mined

Mitigation Option	Contribution of capital to the unit cost of coal Rs/tonne	Operating Cost per unit of coal Rs/tonne
Levelling and grading, terracing, drawing	32.9	14.35
Preparing pits, plantation of saplings, fencing, guarding, maintaining	-	0.35
Black topping of haul roads, dust collectors in drills, dust suppression in processing plant, water spraying, green belt, maintenance of Heavy Earth Moving Machinery (HEMM).	9.1	2.8
Industrial water treatment, domestic effluent treatment, mine water sedimentation, collecting and treating surface run-off water.	3.15	1.05
Operators' cabins in equipment, maintenance of equipment, personnel protective equipment	1.05	-
Afforestation, plant nursery, habitat conservation.	3.15	1.75
Rehabilitation and resettlement of affected populace, community development work.	0.35	0.35
TOTAL	49.7	20.65

Source: Mitigation options in Coal Mining in India, Ghose, Bose & associates, Ltd., June 1997.

The total environmental mitigation cost is about 70 Rs/ tonne of coal. It varies little among the grades of coal mined. The environmental costs are presented as a percentage of project cost in *Table* 2.42. The coal prices used in the calculation are economic values estimated by considering the relative prices that power stations would be prepared to pay.

Table 2.42 *Gradewise Economic Costs of Coal & Environmental Operating and Capital Costs*

Grade	Economic value (Rs/t)	Capital contribution to control cost (%)	Operating control cost (%)	Total environmental mitigation cost (%)
G	580	3.6	8.6	12.2
F	815	2.5	6.1	8.6
E	1090	1.9	4.6	6.5
D	1350	1.5	3.7	5.2

The normal pollution control systems that are required for coal fired power plant in India are:

- air pollution control
  tall stack to disperse flue gases
  low NOx burners
  space provision for retro-fitting FGD
  high efficiency ESP
  dust suppression and extraction systems at coal handling plant
  green belt development and afforestation

- water pollution control
  pit for pH adjustment of the DM plant regeneration-waste
  central effluent treatment plant
  sewage treatment plant in the colonies

- solid waste disposal
  disposal of fly ash and bottom ash.

Typically, the cost of these mitigation measures in a conventional pulverised coal plant in India works out at about 7% of the project cost. This does not include R&R costs that are site-specific. The absolute and percentage costs for the various components on a 500 MW coal fired plant costing Rs 24620 million are given in *Table* 2.43.

Table 2.43 ***Absolute and percentage cost of mitigation measures on a coal-fired power plant.***

Control Measure	Cost (mn Rs)	% of environmental cost	% of project cost
high stack	180	10.3	0.73
ash pond and liner	360	20.7	1.50
electrostatic precipitator	650	37.4	2.64
ash handling plant	500	28.7	2.00
environmental monitoring and laboratory facilities	10	0.6	0.04
green belt	10	0.6	0.04
effluent treatment plant	20	1.2	0.08
coal dust extraction suppression	10	0.6	0.04
TOTAL	1740	100	7.00

Source: Mitigation Options in Power Generation in India, Ghose, Bose & associates, Ltd., March, 1997.

Other Studies

The Bureau of Industrial Costs and Prices sponsored a major study on environmental issues in coal mining and the associated costs, conducted by TERI and published in November 1993. (1) This study analysed environmental costs at 30 mines in India. Two financial cases were applied: Case I used a discount rate of 12% with an equipment lifetime of 9 years and Case II used 12% but with an equipment lifetime of 15 years. *Table 2.44* gives average environmental costs, separated into Open Cast and Underground Mines. Both financial and economic costs (2) are reported, with economic costs ranging between 8.87 and 9.26 Rs/t and financial costs being 11.80-12.29 Rs/t. Costs are slightly higher for open cast mining. The results are consistent with the gradewise costs shown in *Table 2.42*. If overburden rehandling is required, this adds a significant extra cost. The Study found that rehandling 10% of the overburden would add between 14 and 36 Rs/t to the overall coal costs.

Case Study of Koel-Karo HE Power Station

The environmental impacts of hydro projects are case specific. The following account describes the contribution to the total project cost for the largest scheme under consideration in the two States studied.

(1) Tata Energy Research Institute, Study of Environmental Issues in Coal mining and Associated Costs, November 1993

(2) In the study, to obtain economic costs a conversion factor of 0.81 has been applied to financial costs of equipment used in land reclaimation and anti-pollution measures. The conversion factor was given by CIL officials.

Table 2.44 ***Weighted average Environmental Cost over 13 Coalfields***

Mine Type	Production (Mtonnes)	CASE I Financial (%)	Economic (%)	CASE II Financial (%)	Economic (%)
Open Cast	169.46	12.57	9.35	12.00	8.89
Underground	52.56	11.37	8.99	11.14	8.81
TOTAL	222.02				
Environmental Cost (Rs/t)		12.29	9.26	11.80	8.87

This project would use the water of the river South Koel and its tributary North Karo river in Bihar to generate about 710 MW of power. It is designed to provide peaking electricity to the Eastern Regional grid of India that is largely coal based.

The project comprises a 44m high and 4710 m long earthen dam on the river Koel near Basia to create a reservoir with a capacity of 1730 mn m3 and a 55m high 3850 m long earthen dam on the North Karo river near Lohajimi to create a reservoir with a gross storage capacity of 702 mn m3. 70 cumsecs of water would be diverted through a 34 km long channel from the South Koel basin to the North Karo basin. 510 cumsecs of water would be diverted from the Lohajimi reservoir through a 11.2 m diameter 1400m long head race tunnel to an underground power house of 4 x 172.5 MW (690 MW) at Lumpungkhel. At the tail end of the canal a 20 MW surface power house would generate 20 MW from the pressure drop in the channel.

This is an enormous project by any standards. It is situated in the high plateau of Chotanagpur famous for its natural beauty, luxuriant forests and wide range of wildlife. Chotanagpur has the largest concentration of tribal peoples in India. There is an acute conflict with environmental interests.

The potential was first investigated by the Bihar State Electricity Board in the 1960s and a project costing 1.32 bn Rs was proposed in 1973. The project passed to the NHPC in 1980 and the cost re-estimated at 392 Crores. The project was approved by the GoI in cabinet in 1981. The cost was again increased to 9.30 bn Rs in 1986 and to 10.37 bn Rs in 1988.

The project would use about 23,000 hectares of land of which some 16,000 are private and some 900 are forest. 10,000 families would be displaced; the local affected people are predominantly tribal. 112 villages will be affected of which 20 will be affected by more than 80% and the occupants therefore will be fully resettled in nearby villages. Another 21 villages will be partially resettled. Land acquisition has been the main problem and has prevented the start of the project.

The Government of Bihar specified in a government resolution in January 1986 the measures to be taken for the rehabilitation of the local people and the principles to be observed in compensating the loss of land. The main aspects of the compensation for affected people are:

- land will be provided for churches, burial sites, cremation grounds and other places of worship and help given with reconstruction;
- civic amenities like drinking water, primary schools, health centres will be made;
- the compensation for land acquisition will be determined as the capitalisation of 15 years of the yield or the prevailing market price at the choice of the family;
- every displaced family will be given land for a homestead; and
- there is also provision for preference in employment on the project and in the region and through rehabilitation by training and the offer of small contracts on the project.

The provision for the compensation of land, places of worship, houses, trees etc. was set (in 1989) at 952 mn Rs. This is broken down in *Table 2.45.* Additional costs for rehabilitation are shown in *Table 2.46.*

The rehabilitation of displaced persons is estimated to cost 132 mn Rs. New residential and non-residential buildings are estimated at 219 mn Rs. 2.4 mn Rs were provided in the cost estimate for local reforestation. Some 1280 mn Rs were therefore provided for resettlement and rehabilitation. However, observers in the field have remarked that the land compensation has not been sufficient and therefore the costs should be regarded as being on the low side for similar R&R activities.

The approval of the project by the Ministry of Environment and Forests required that 870 hectares of land be reforested to compensate the loss of virgin forest. 106 mn Rs were provided for this and other environmental and ecological purposes.

The sum of costs in the project to compensate for social and environmental damage is therefore some 1400 mn Rs. This can be compared to the total estimated project cost at the time of about 10 billion Rs, i.e. some 14%. The provision in the 1989 estimate was numerically the same as in the 1986 estimate based on the government resolution, as other costs had risen on average over the period by at least 10% it seems likely that R&R costs would have done also. 15-16% therefore seems more likely, assuming that the provisions of the government resolution are fair and have been fairly interpreted.

The R&R costs of this project are a substantial fraction of the total project cost; its cost-effectiveness is therefore sensitive to any increase in R&R costs. If this is typical of hydro projects and if (as appears likely) R&R costs of coal mining and coal fired power plant are lower then it suggests domestic coal would be advantaged by any upward revision of R&R costs compared to hydro, though not of course compared to imported fuel.

Table 2.45 Detailed Costs of Compensation

Item	Amount	Provision (mn Rs)
Cultivatable Land	2836 hectares	188
non-cultivatable Land	12700 hectares	583
gardens and roads	1160 hectares	41
Houses	10,000	70
Places of worship		12
Other		28
TOTAL		952

Table 2.46 Costs of Rehabilitation

Item	Amount	Cost (mn Rs)
Land for rehabilitation	1343 hectares	50
Grant in aid and transport grant	10000 families	18
Cost of land development		17
Approach roads	126 km	38
Health sub-centres	41	21
Primary schools	41	12
Miscellaneous		50
TOTAL		206

2.3.3 *The Evidence from Andhra Pradesh*

Fuel Costs and Candidate Plants

The demand forecast in IFS is assumed to be the same as in BAU. The costs on the supply-side are as in *Table* 2.29 of *Section* 2.2.2. The fuel costs are economic costs including the control costs required to reduce the environmental impacts to the level specified by present standards in India. *Tables 2.47and 2.48* show how the levelised cost of selected generic options are affected by the change from financial to economic costs.

Table 2.47 Levelised Financial Costs in Rs/kWh for Specified Running Hours

	Capital Cost (kRs/kW)	Fuel Cost (Rs/MMBTU)	5000 hrs	6000 hrs	7000 hrs	8000 hrs
Singareni (pit head)	40	54.1	1.85	1.66	1.52	1.42
Talcher (pit head)	64	37.6	2.27	1.98	1.77	1.62
Singareni (load centre)	43	72.9	2.13	1.93	1.79	1.68
Talcher (load centre)	43	86.2	2.28	2.08	1.93	1.83
Imported Coal (coastal)	43	101.4	2.40	2.19	2.05	1.94
Naphtha	35	154.1	2.04	1.88	1.77	1.69
LNG	32	136.5	2.11	1.97	1.87	1.79

Source: Andhra Pradesh Case Study, ASCI Consultancy, 1998.

Table 2.48 Levelised Economic Costs in Rs/kWh for Specified Running Hours

	Capital Cost (kRs/kW)	Fuel Cost (Rs/MMBTU)	5000 hrs	6000 hrs	7000 hrs	8000 hrs
Singareni (pit head)	33.3	75.3	1.91	1.75	1.64	1.55
Talcher (pit head)	57.3	48.1	2.22	1.96	1.77	1.63
Singareni (load centre)	35.8	87.4	2.11	1.94	1.82	1.72
Talcher (load centre)	35.8	81.1	2.04	1.87	1.75	1.65
Imported Coal (coastal)	35.8	100.1	2.20	2.03	1.90	1.81
Naphtha	29.2	182.4	2.09	1.96	1.86	1.79
LNG	26.7	136.5	1.98	1.86	1.77	1.70

Source: Andhra Pradesh Case Study, ASCI Consultancy, 1998.

The Tables are an interesting comparison. The move from financial to economic costs improves the position of LNG versus domestic coal and especially compared to naphtha. Only Singareni pit head and Talcher load centre are cheaper than LNG at 7000 hours running in the economic case, whereas all but Talcher load centre are cheaper in the financial case. Imported coal also gains compared to domestic sources.

The Expansion Plan

The simple comparison of levelised costs is only a partial insight into the power system planning exercise; it is also necessary to take into account load shape, permitted rates of construction and resource limitations. The results of the full power system modelling do show as expected that imports of coal and LNG appear earlier and penetrate more strongly than in BAU. It is mainly the coal from Singareni burnt in load-centres that is displaced; Talcher coal increases its market share.

The fuel-burn at the beginning and end of the period under BAU and IFS is shown in *Table 2.49*. The greater importance of imported coal and LNG in the IFS case is clear. Naphtha is displaced by LNG in the IFS scenario.

Table 2.49 Electricity by Fuel Compared in the BAU and IFS Scenarios (TWh).

	Talcher Coal	Local Coal	Local Gas	Naphtha	Hydro	Coal Imports	LNG	Total
1996/7	8.4	13.8	1.5		9.4			33.0
BAU 2015	57.2	31.5	4.9	5.5	9.6	16.0	2.3	127.2
Reform 2015	59.3	22.9	5.1	4.3	9.6	20.5	5.8	127.7
IFS 2015	58.3	27.4	4.6	1.5	9.6	21.6	12.1	135.2

Source: Andhra Pradesh Case Study, ASCI Consultancy, 1998.

Environmental Impacts

A comparison of the emissions in the Reform and IFS scenarios is given in *Table 2.50*. The IFS scenario shows very little difference from BAU. The faster growth of cleaner fuels towards the end of the period does not show up strongly in the present value attributes adopted.

Table 2.50 Comparison of Emissions in BAU, Reform and IFS Scenarios

Year	Cumulative CO_2 mt	pv of Nox kt	pv of SOx kt	pv of TSP kt	Cumulative Ash mt
BAU	1240	2550	2497	251	254
Reform	1138	2390	2363	233	226
IFS	1235	2576	2552	252	251

Source: Andhra Pradesh Case Study, ASCI Consultancy, 1998.

2.3.4 *The Evidence from Bihar*

Fuel Costs and Candidate Plants

Data on the economic costs of candidate plant are given in *Table 2.51*.

Table 2.51 Capital Costs of Generation

	Capital Cost (Rs/kW)	Mitigation Cost (Rs/kW)	Total Capital Cost (Rs/kW)	Fuel Cost (Rs/kWh)
New 500 MW coal	38232	2878	41110	0.86
Coal 210 MW extension	26877	2023	28900	1.00
CCGT	22951	469	23420	1.23
Hydro	39641	809	40450	0
Biomass	29760	2240	32000	0.35
IGCC	46407	2443	48850	0.81

Source: Bihar Case Study, SCADA, 1998.

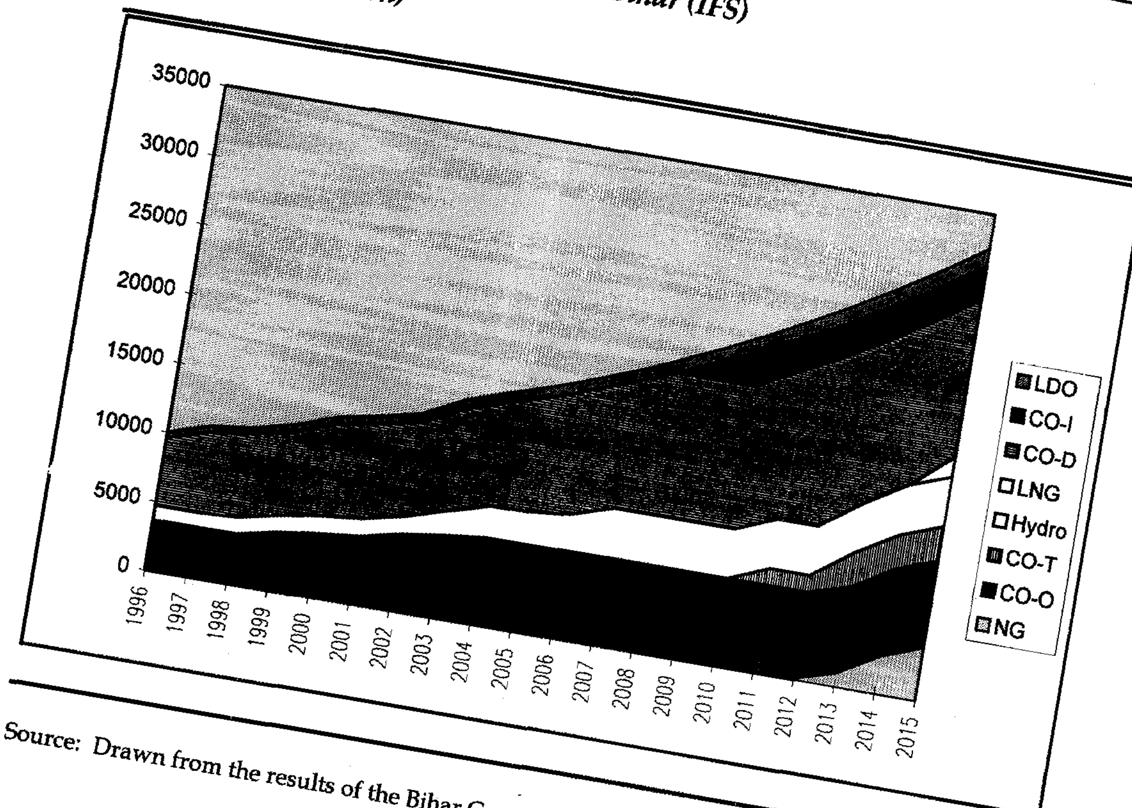
The Expansion Plan

The expansion plan obtained under the IFS assumptions contains a range of out-of-State options. A new pit-head coal plant is built in Talcher and an imported coal plant is built outside on the coast. These plant are additional to the gas from Bangladesh and the LNG imports that are selected in the Reform scenario. The extra plant are required because the demand in the IFS scenario is 900 MW higher than in the Reform case.

Figure 2.7 shows the generation by fuel over the period. The Figure nicely demonstrates the wide range of options that are available to Bihar in the Inter-Fuel Substitution Scenario. LDO is light distillate fuel burnt in captive plants; this increases slightly in volume over the period, but falls in percentage terms. Domestic coal (CO-D) remains the main stay of the system. CO-O designates other coal that comes from out-of-state, but excluding supplies from Talcher 2, that are separately indicated as CO-T. "Other Coal" increases up to 2007/8 and then remains steady. Talcher 2 comes in at 2010 and then increases to the end of the period. Imported coal (CO-I) comes in at around 2008. Hydro plant increases steadily to 2007, after which no new plant is built. Significant imports of natural gas (NG) from Bangladesh come in from 2012/13. LNG imported at coastal sites appears right at the end of the period.

After 2008 all the incremental supplies arise from source outside Bihar; imported coal and natural gas and coal from Talcher provide all the incremental supplies from that date.

Figure 2.7 ***Generation by Fuel in Bihar (IFS) (GWh)***



Source: Drawn from the results of the Bihar Case Study, SCADA, 1998.

Environmental Impacts

The environmental attributes for the BAU, Reform and IFS scenarios are given in *Table 2.52*. The Reform scenario envisages the deep rehabilitation of existing plants with a beneficial effect on thermal efficiency and environmental performance; this deep rehabilitation was not foreseen in IFS. The effect of the rehabilitation is to bring emissions down. The comparison draws attention to the marked environmental benefits from rehabilitating old power plant.

Table 2.52 ***Summary of Emissions under the BAU, Reform and IFS Scenarios***

Year	Cumulative CO_2 mt	pv of NOx kt	pv of SOx kt	pv of TSP kt	Cumulative Ash mt
BAU	142	804	929	62	36
Reform	127	685	828	54	34
IFS	141	732	913	60	37

Source: Bihar Case Study, SCADA, 1998.

2.3.5 *The Implications for All-India*

The trends identified in the Case Studies of Andhra Pradesh and Bihar have been extended to all-India using the Environmental Manual for Power Development (EM) described earlier. The procedure was identical to that described for BAU, but using the fuel shares calculated for IFS.

The development of the fuel consumption on the Indian power system under IFS is shown in *Table 2.53*, with the results shown as a difference with BAU results subtracted from IFS. The results for IFS are similar to those obtained under the BAU scenario. The major difference is in the generation of power from natural gas, which at the end of the period is responsible for 145.1 TWh of electricity generation in the IFS scenario compared to 115.5 TWh in the BAU scenario (an increase of 26%). This increase is at the expense of domestic coal (which decreases from 797.9 TWh in the BAU scenario to 765.6 TWh in IFS) and naphtha, where electricity generation falls from 29.9 TWh to 9.9 TWh.

The estimates of emissions for all-India are presented in *Table 2.54*, again with BAU results subtracted from the IFS result. The generation fuel changes between the IFS and BAU scenarios result in reductions in annual emissions of 3.5% CO_2, 0.6% SO_2, 2.8% NOx and 3.6% of particulates by the end of the period.

Table 2.53 Electricity Demand Split by Generation Source (TWh): IFS-BAU

Year	Hydro	Coal-Imp	Coal-Dom	Gas	Naphtha	Nuclear	Total
1993/94	-	-	-	-	-	-	-
1996/97	0	0	-0.5	+0.5	0	0	0
2001/02	0	0	-10.3	+10.8	-0.6	0	0
2006/07	0	0	-5.7	+11.2	-5.5	0	0
2011/12	0	+20.4	-11.5	+5.1	-14.1	0	0
2014/15	0	+22.8	-32.3	+29.6	-20.0	0	0

Table 2.54 Emission Calculations for "All India": IFS - BAU

Year	CO2 (million tonnes)	SO_2 (k tonnes)	NOx (k tonnes)	Particulates (k tonnes)	Ash (million tonnes)
1996/97	0	-10	-10	0	0
2001/02	-9	-60	-40	-60	-2
2006/07	-10	-60	-40	-40	-2
2011/12	-26	+90	-10	-50	-2
2014/15	-27	-30	-100	-170	-6
Cumulative	-185				-38

These results highlight the importance to India of developing a sound policy towards natural gas utilisation. Indigenous gas is scarce in India. Scarcity is managed not by prices but administered through a distortionary system of gas allocations. Most of the present gas supply of about 17 BCM is allocated to the fertiliser (44%) and power (40%) sectors. The Special Study on Inter-Fuel substitution projects that gas shortages in India are likely to continue in the future: against a demand forecast in the range of 53.7-82.9 BCM in 2006/07, indigenous gas production is expected to level off between 24-30 BCM over the next decade. Constraints on the gas transportation infrastructure further impede development of gas markets. If the power sector's additional requirements for natural gas that would follow from the economic pricing of gas are to be met, the policy towards gas utilisation would have to be revised: for example, natural gas imports could be liberalised and the allocation system for indigenous gas replaced by a market-based mechanism.

The temporary rise in emissions of sulphur in 2011/12 is due to the penetration of imported coal that is taken to be 1.5% sulphur. Even with this pessimistic assumption the environment is improved in all aspects by 2014/15 as a consequence of choosing fuels according to their economic cost.

2.4 *Renewable Energies Would Improve the Environment, but How Much Would It Cost?*

Renewable energies would improve the environment, but whether they are a practical policy depends on how much their effect would be and the cost? This scenario explores the consequences for the environment of optimistic assumptions regarding the costs of renewable energy technologies. It poses three subsidiary questions:

- what is the resource potential for renewable energy?
- how much could be practically developed and what would it cost?
- what are the consequences for the environment?

2.4.1 *The Evidence from Andhra Pradesh*

Andhra Pradesh has a long coastline with a favourable wind regime. The estimated wind potential is 800 MW; the present installed capacity is around 44 MW and there are proposals for another 370 MW from the private sector. The plant load factor is low, typically 22%, so the levelised costs of generation are high. Peak output from the wind turbines occurs during the monsoon season, but demand for electricity is highest in the dry season. Wind energy therefore has to be forced into the power system expansion. The existing private sector interest is driven partly by tax breaks.

The potential for mini hydro, including projects on irrigation canals, is variously estimated up to 4000 MW. The existing capacity of mini hydro is 11 MW and some 5 MW more are in construction; a formidable obstacle to the development of irrigation canal drop schemes is the need to co-ordinate with the state irrigation departments. A study of the potential for Integrated Resource Planning carried out in Andhra Pradesh with funds provided by USAID concluded that 170 MW of mini hydro was economically viable. After discussion with APSEB and independent experts, and recognising that this work wished to take a generous view of the potential for renewables, a potential of 400 MW was considered to be cost-effective and practical.

The plant load factor is around 40% and the levelised costs of generation are lower than for wind. Peak output from these plants occurs during the irrigation season, which is also the time of peak demand on the power system. Nevertheless, mini hydro is not selected by the expansion plan and has to be forced in.

Solar Photo Voltaics (SPVs) and solar thermal were not considered for AP, due to the high economic cost compared with other renewables (see *Section* 2.4.3). Also although sugar cane is grown in Andhra Pradesh, most of the bagasse is used in paper-making. Whilst this may not be an optimal use of bagasse, no bagasse based cogeneration was included.

The total potential of candidate renewable energy technology (RET) generation of 800 MW represents about 6% of capacity by 2014/5, or about 8-9% of the capacity addition over the period. The contribution in terms of GWh is less, because of the low load factors on the plant. These relatively small contributions from RETs do not greatly alter the least cost expansion plan from that identified in IFS; conventional plant is delayed as the RETs are introduced, but the choice of technology and fuel is otherwise similar. The overall system cost is higher, because the RETs are not an optimal choice.

The attributes of this scenario are compared to IFS in *Table* 2.55. The RET scenario has a higher cost and a lower environmental impact as measured by every attribute. The total reduction of each impact, though useful, is not dramatic, suggesting that RETs can only be a small part of any strategy for managing the environmental impacts of the power sector.

Table 2.55 Environmental Attributes of the Renewable Scenario for Andhra Pradesh

Attribute	RET	IFS
PV of cost (bn Rs)	762	742
PV of SO2 (kt)	2487	2552
PV of NOx (kt)	2521	2576
PV of TSP (kt)	245	252
Cumulative CO2 (mt)	1199	1235
Cumulative Ash (mt)	240	251
Land Use (ha)	1920	2008

Source: Andhra Pradesh Case Study, ASCI Consultancy, 1998.

2.4.2 *The Evidence from Bihar*

Wind speeds in Bihar are not high enough to provide economical power generation. Wind energy is therefore not considered as an option. As in the case of AP, solar PV and solar thermal were not included, due to their high costs compared with other renewables (*section* 2.4.3).

There is an estimated 148 MW of small hydro on over one hundred sites in Bihar. The resource is being developed by the Bihar Hydroelectric Power Corporation. 74 MW are included in the IFS scenario and all 154 MW are included in the renewable scenario.

Sugar cane is grown in large quantities in Bihar. The state produces 1.5 mt out of 75.5 million tonnes grown annually in India. Bagasse in now used mainly for raising process steam. If used for power generation it is estimated that biomass could contribute 400 MW in Bihar. The plan assumes also that 10 MW of plant burning biomass in boilers could be constructed over the period and a further 10 MW of biomass might be gasified for power generation. The total capacity of plant added is some 570 MW, or about somewhat more than 10% of the forecast increase in peak demand. The comparison of cost and environment as RET and IFS scenarios are in *Table 2.56.*

Table 2.56 Comparison of Cost and Environmental Attributes for RET and IFS Scenarios

	Cost (bn Rs) (pv)	SO_2 (kt) (1996-2014) (pv)	NOx (kt) (1996-2014) (pv)	TSP (kt) (1996-2014) (pv)	CO_2 (mt) (1996-2014)	Ash (mt) (1996-2014)
IFS	198.1	913	732	60.3	141	36.7
RET	196.4	895	722	58.9	139	36.4

Source: Bihar Case Study, SCADA, 1998.

The present value of cost in the RET scenario is slightly lower than that of the IFS, showing that some at least of the RET potential is cost-effective. The environmental attributes are all improved.

2.4.3 *Renewable Energy In India: A Special Study*

This study, conducted as part of the overall work programme, analysed the Renewable Energy sector of India in detail. Analyses of the current status of renewables in India, their economics and the effects of constraints and Government policy were used to make projections of the penetration of renewables to the year 2011/12. The study had a firm economic basis, with projections made from a least cost optimisation model comparing renewables to other forms of generation.

Costs of RETs

The economic viability of RETs was assessed in the study based on Levelised Annual Cost (LAC). LAC is defined as annualised cost (Rs) divided by annual net electricity generation (kWh). It should be noted that LAC does not allow for the controllability of energy and thus tends to flatter options such as wind (whose energy availability depends on the weather) compared to cogeneration using bagasse.

Table 2.57 *LAC of RETs*

	Wind	Small Hydel	SPV	Solar Thermal	Cogen	Biomass combustion (bagasse)	wood gasification
Capital cost (Rs Crore/MW)	3.50	3.50	20.1	11.0	2.5	3.5	3.5
O&M costs (as % of capital cost)	2	2	1	1	2	2	2
LAC Rs/kWh	2.95	1.43	13.24	10.36	2.33	1.69	2.12

Source: Renewable Energy in India: A Special Study, ERM India

Table 2.57 (above) indicates that both SPV and Solar Thermal Power are far less economically viable than the other technological options. At a global level, the prices of SPV modules have reduced substantially from $100 per Wp (peak Watt) in 1973 to $5 per Wp in 1990. The current estimated costs are around $4-5 Wp and are further expected to decrease to $2-3 per Wp during the next five years. In the Indian context there has also been significant reduction in prices in recent years. Indeed, the Ninth Plan for India has set a target to bring down the price to Rs110 ($3) per Wp by 2001/2. The price used in the analysis for the Special Study is based on a cost of $5 per Wp (Rs20 Crores/MW). Even if the price falls by 50% to approximately $2.5 per Wp the technology would remain uncompetitive compared $1.05-1.35 per Wp (Rs 3.5-4.5 Crores/MW) for other RET and conventional technologies.

The costs of renewable energy supply discussed above do not take into account the economic advantages of the options' abilities to generate localised power in remote rural areas compared to conventional grid-based power which would incur additional transmission costs. The special study calculated the economic costs of renewable energy supply and grid-based energy supply to off-grid locations, presented in *Table 2.58*.

Table 2.58 Supply cost of power at a remote location

System	Cost of Supply (Rs/kWh)
Grid system	2.20
Decentralised system:	
wind	2.87
small hydel	1.43
wood gasification	2.12
biomass combustion (bagasse)	1.69

Source: Renewable Energy in India: A Special Study, ERM India

Apart from wind, all other decentralised modes of generation are economically more favourable than grid supply to meet the demand at remote locations. At the National NGO Workshop, NGOs emphasised the important role that RETs had to play in decentralised power generation; the success that had been encountered at the grass-roots level, in villages and remote regions; and the desirability of taking up pilot demonstration projects for small-scale power generation, using RETs such as gasifiers, solar PVs and micro-hydro.

Potential Penetration of RETs

Two Cases were developed in order to assess the influence of Government policy on the penetration of renewables:-

1. *Case I* is a continuation of present Government policy, with present fiscal/financial incentives provided to power generation technologies carried through the time horizon of the study;
2. *Case II* assumes that there will be no incentives. Economic costs of power generation are used as the model inputs.

Further sensitivity analysis was conducted by considering the effects of varying plant load factor (e.g. wind between 15 and 30%, mini hydro between 30 and 45%) and by varying the capital costs of the mix of renewable technologies between Rs 30,000/kWe and Rs 50,000 /kWe.

'Best estimate' results are shown in *Table 2.59.* Projected capacity of all generating plant is included for comparison purposes. In *Case I*, Renewables contribute 3.4% of capacity in 2001/2, 3.5% in 2006/7 and 3.8% in 2011/12. *Case II*, where incentives are not given, reduces this share to between 2.3 and 2.5% of total capacity in the projection period. The results for *Case I* are consistent with the Indian Government target of 4400 MWe installed capacity by 2001/2.

Table 2.59 Special Study Renewables Penetration Projections (GW)

Installed Capacity, Gwe	2001/2	2006/7	2011/12
Case I: Renewables	4.5	7.1	11.0
Case II: Renewables	3.1	4.9	6.7
Case I: All Generators	133	201	287
Case II: All Generators	132	200	285

The incremental contribution from 2001/02 to 2011/12 is 4.3% in *Case I* and 2.4% in *Case II*. This suggests that to increase the share of renewables in the fuel mix, subsidies must be maintained.

Mini hydro, wind and bagasse cogeneration are projected to supply virtually all of the electricity generated from renewables. For the low capital cost scenario, *Table 2.60* shows that the contributions made by these three technologies are similar. The figures are the same in both *Case I* and *Case II* and are not affected by the level of fiscal and financial incentives available under *Case I.*

The penetration of small hydro is independent of both case and capital cost even when capital costs are raised to Rs 50,000/kWe. Both wind and cogeneration technologies require fiscal/financial incentives: their projected penetration decreases by over 50% when their capital costs are Rs 40,000 /kWe or higher.

Table 2.60 Renewable Energy Supply by Technology

Electricity Supply, TWh	2001/2	2006/7	2011/12
Small Hydro	4.73	7.80	10.95
Wind	4.71	7.82	10.95
Cogeneration	4.82	9.21	13.61
Solar Thermal	0.06	0.06	0.06
TOTAL	14.32	24.89	35.57

The results from the Special Study are broadly in line with those from the RET scenarios for Andhra Pradesh and Bihar. Small hydro, wind and bagasse cogeneration are the most important technologies and their relative importance is dependent on the renewable resources in the area under consideration. The Special Study projects that RETs will account for between 2.3 and 3.9% of electricity generation capacity by 2011/12 depending on the level of fiscal/financial incentives. This range is lower than the figures used in the RET scenarios in Andhra Pradesh and Bihar, but the Special Study does not take account of the use of renewables for emissions abatement; it considers their economic case only. Both studies show that renewables will not be a large contributor to electricity generation in India in the short- to medium-term.

2.4.4 *The Evidence from Other Studies in India and Elsewhere*

It has been estimated by the Ministry of non-Conventional Energy Resources that some 126 GW of power generating capacity is available in renewable resources. The breakdown of this total by type of technology is given in *Table 2.61.*

Table 2.61 Technical Potential for Renewable Energy

Technologies	Units	Potential
biogas plants	nos.	12 million
biomass	MW	17,000
improved wood-stoves	nos.	120 x 10^6
solar energy	MW/km2	20
small hydro	GW	10
wind	GW	20
ocean energy	GW	50
wave power	GW	20
tidal power	GW	9

Source: MNES Annual Report, 1996-97.

This is a vast potential, but many of the technologies are costly and far from commercial viability.

By the end of 1996 the total capacity of renewable energy in the country was almost 1100 MW, made up as shown in *Table* 2.62. The target for the Ninth Plan is to have installed capacity of 4,400 MW by 2001/2. The dissemination of renewable technologies in India is supported strongly at National level; the Ministry of non-Conventional Energy Sources has this exclusive function.

The first wind-farms in India were installed in the coastal areas of Tamil Nadu, Gujarat, Maharastra and Orissa. The main potential is in these and other states of South India. The Case Study of Andhra Pradesh is therefore an appropriate reference for the contribution that wind might make to power system development and the alleviation of environmental impacts.

Table 2.62 Installed Capacity of Renewable Energy by March 1996

Technology	Capacity (MW)
biomass (cogeneration)	55
biomass (combustion)	-
biomass (gasifiers)	70
small hydro	134
wind	825
solar photovoltaics	6
Total	1090

Source: MNES Annual Report, 1996-97.

The estimate of total potential varies among authorities. The estimate of 20 GW made by the MNES is at the lower end of the range; TERI has estimated 50 GW. Estimates of economically viable resources are more difficult. Ninety eight sites have been identified with annual mean wind speeds of more than 18 kmph; these would provide 5,000 MW and are likely to be close to economic. This 5,000 MW represents about 2 % of the likely capacity requirement of about 250 GW for all India in 2015. In the Andhra Pradesh case study the total installed capacity of wind turbines is equivalent to about 4% of peak demand in 2015. It is appropriate to err on the high side in evaluating the potential of renewables as a means of mitigating environmental impacts in the power sector, so the Andhra Pradesh study is a fair reference for understanding the situation in all-India, so far as wind is concerned.

An estimated potential of 10,000 MW of small hydro power (SHP) exists in India. The estimates are contentious because every time water runs down hill it is in a sense a prospective source of power generation; the real questions are what does it cost and where should the line be drawn. The MNES has examined 2679 potential sites with capacities up to 3 MW; it estimates that just over 2,000 MW would be available. This represents 1% of the likely installed capacity in all-India by 2015. The 400 MW SHP resource in Andhra Pradesh is about 2% of peak demand, so again the study is a reasonable reference.

India has high rainfall and insolation; the rate of photosynthesis is high in many areas and therefore biomass is a prospective resource for energy. The priorities identified by the MNES are bagasse based cogeneration, direct combustion of biomass and gasification of biomass. At present there are 18 biomass projects with an installed capacity of 69 MW and another 17 projects under construction with a capacity of 97 MW. The estimated potential of bagasse cogeneration in India is 3500 MW in 420 mills. The MNES believes that 2,600 MW could be installed in the next ten years.

The potential in India for generating power from crop residues and other sources of biomass is undoubtedly large. There are however technical problems. Biomass is a complex and variable material with difficult combustion properties. There are also logistical problems in ensuring adequate and timely supplies of fuel of a proper quality throughout the year. Many demonstration plants have been begun in India, and the experience has been mixed. About 100 MW of projects are foreseen in the 9th Plan to 2001/2.

Gasification technology for decentralised power generation has been developed and demonstrated. The difficulties should not be underestimated. A gasifier comprises a small chemical plant producing low quality fuel from a low grade feed-stock of variable quality. The fuel is often contaminated, may be difficult to burn or even damage the engine. The process can be made more reliable by using better quality and more homogenous feed-stocks, such as charcoal and by thorough cleaning of the gas. This costs money and adds to the complexity of the process and the needs for maintenance.

About 16 MW of gasifiers have been installed in India with a capacity of about 16 MW. In 1993 about 20% of the installed gasifiers were surveyed. Roughly 57% were found never to have been used after commissioning and some 5% were never commissioned after delivery of the materials. Only 14% were operating as expected. Clearly there is a long way to go before the potential such systems can make is demonstrated.

The Case Study of Bihar assumes 400 MW of bagasse cogeneration and 10 MW each of biomass combustion and gasification. The 400 MW of cogeneration is some 10% of the peak demand, so it makes a much higher contribution to capacity than would be possible over all India. The 10 MW each of biomass combustion and gasification are generous given the present uncertainties surrounding these technologies. Together they represent about 0.5% of the expected capacity addition in Bihar.

The technical potential of solar energy in India is vast. The country receives annually enough solar energy to generate over 500,000 TWh of electricity, assuming 10% conversion efficiency. This is three orders of magnitude greater than the likely demand for electricity by 2015.

Whilst still relatively expensive there are many emerging niche markets and the technology has value for rural development in areas remote from grid systems. Recent experience in Rajasthan, which has an exceptionally favourable solar regime, indicates that despite falling costs it may be some time (beyond 2014/15) before SPVs make a significant contribution to energy supply. Central solar power systems have been investigated and international companies have shown interest. Whilst progress has been made with regard to international companies securing power purchasing agreements none have started to date.

2.4.5 *Conclusions and Implications for All-India*

The case studies of Andhra Pradesh and Bihar are satisfactory references for an analysis of the contribution that renewable energy can make to managing the environmental impacts of the power sector in India. Andhra Pradesh is a good example of the what can be done with wind and small hydro; Bihar is a good example of what can be done with biomass. In each case the volume of renewable energy that is assumed is high compared to the potential for all-India.

The Case Studies show that the grid connected renewable energies are not often a part of the least cost expansion plan. They do make a contribution to reducing environmental impacts, but at a cost. It can be that the levelised cost of electricity from renewables compares quite well to that of conventional source, but it is still not picked up by the planning model. The levelised cost is the total capital and operating cost of the respective technologies divided by the total output of electricity. This calculation does not make full allowance for the fact that the renewable energy may not be available at the times of system peak and may therefore not reduce the capital investment that is required on the system.

The overall conclusion in the context of this project is that although the economically viable potential of renewable energy is limited, there are technically viable options that have large potential at rather high cost.

2.5 *DEMAND SIDE MANAGEMENT WOULD IMPROVE THE ENVIRONMENT, BUT HOW MUCH WOULD IT COST?*

The use of energy is normally less efficient and less cost-effective than the best available technology would allow. It is therefore reasonable to seek policies to limit consumption of electricity rather than building more, new generating plant. This sections examines the questions:

- what is Demand Side Management (DSM) and how can it be achieved?
- what is the potential in India?
- how much could be practically developed and what would it cost?
- what would be the environmental benefit?

2.5.1 *DSM and its Implementation*

There are many reasons for the apparent inefficiency of energy use compared to supply and they are well documented. Among them are:

- the high costs of changing or adding to existing plants;
- the tendency of industrial consumers to manage risk by minimising investment and focusing on production;
- ignorance of the technical possibilities; and
- landlord-tenant problems where the investor cannot see a direct return.

Governments have tried to identify mechanisms to promote the take-up of energy efficient practices by removing or lowering these obstacles. These mechanisms are often collectively known as Demand Side Management. This term encompasses several different approaches that would be better distinguished. Some commonly occurring examples are:

- measures that are directly funded and implemented by utilities, (mandatory or voluntary);
- measures that are directly funded and implemented by third parties;
- funding of energy conservation programmes through a levy on utilities;
- energy conservation programmes funded out of state budgets;
- measures that permit users of electricity to "bid" demand reductions into a spot market for electricity in the same way as generation (as in the UK); and
- introduction of mandatory efficiency standards and labelling for appliances.

The DSM scenarios used for Andhra Pradesh and Bihar do not consider which of these mechanisms are actually used to implement DSM. These different examples reflect different means of implementation and in particular, different extents and ways of using the utilities. It is not easy to promote energy efficiency because the projects are small, users are many and their priorities lie elsewhere. These fundamental issues are manifest in experience of each of the above approaches.

DSM in its purest sense occurs when utilities fund investments in efficiency on a user's premises. They obtain revenue not only from the sale of electricity to other sectors at higher prices, but also from repayment of the investment. The rationale for this activity is that the utility understands electricity services, so there is no question of ignorance; it is able to recover its expenditure through the regular electricity bill, so there is no landlord-tenant problem; the profit from the investment is shared between the user and the utility. The utility has to accept the risk that the company fails; the company accepts the risk that the investment becomes redundant.

DSM by utilities causes cross-subsidies from users who are not part of the programmes (possibly because they have already made investments) to the participants.

The contractual relationships between utility and user can take many forms. The overall bill of the user should fall and therefore so should the revenue of the utility from selling electricity. The utility will only be a willing participant in this arrangement if its costs decrease more than the loss of revenues. This can only happen if its share of profit from the investment exceeds the loss in revenue from sales. The utility will only have a greater incentive than a third party if the utility was originally selling the electricity for less than its marginal cost of production.

The initial development of DSM took place in the USA, spurred by Regulatory Commissions motivated to reduce environmental impacts. Price regulation was such that the utilities were often unable to recover their marginal costs and therefore there was in many cases some financial benefit to them from DSM.

The rationale for using the electricity supply industry as an agent of energy efficiency policy in a market economy is doubtful. If any part of the electricity supply industry can recover its costs through its prices then it will have a weaker incentive to invest in efficiency than will any third party that meets the criteria of being knowledgeable and having capital available. A more rational market solution is that an independent energy service company (ESCO) should take on the task as a commercial proposition. There has been significant activity along these lines and some degree of success in the USA and Western Europe. The EBRD has investigated and recommended the formation of ESCOs as a means of improving energy efficiency in Eastern Europe.

A difficulty with ESCOs is that the costs of the transactions between the service company and the user can reduce the benefits significantly, if the capital cost of the projects is low. The risks of non-payment or company failure are also present. This is of course a generic problem with DSM, but it is more visible with ESCOs than with utilities within which the costs may be hidden and this is a major advantage of the ESCO formulation.

The UK and in the Scandinavian countries impose a levy on electricity prices to fund energy conservation programmes. Sometimes the utilities also have associated obligations to implement DSM using the funds from the levy, subject to authorisation from a regulatory body. One of the best known DSM programmes in developing countries is in Thailand; the programme is funded from a levy on the sale of oil products. EGAT, the electricity utility, implements much of the programme, subject to technical monitoring and evaluation. It has been difficult to find sufficient appropriate projects and at one stage the Treasury clawed back the accumulated fund.

Generally, with these administered schemes there is a problem of the cost of evaluation and monitoring. Projects need evaluation to ensure that they would not take place anyway, or should never take place at all; evaluation is necessary to ensure the funds are spent as agreed. These arrangements can be quite onerous compared to the benefit from each project.

2.5.2 *The Evidence from Andhra Pradesh*

The Technologies

The DSM scenario in Andhra Pradesh draws upon a detailed investigation of the potential for a wide range of energy efficient technologies and practices analysed under a programme funded by USAID. The technologies, their potential and the estimated total cost of equipment and administration is given in *Table 2.63*. When making a comparison with the IFS scenario the total present value of the cost of DSM measures of 18 billion rupees is added to the total present value of investment in the power system as determined by the power system planning.

Table 2.63 Technologies and their Cost within a 10 year Programme.

	PV of Cost bn Rs	Savings in Year 10 GWh
Urban Lighting	0.49	206
High Eff'y Refrigerators	0.29	167
Solar Water Heating	0.62	146
High Efficiency Pumps	10.01	3453
Metering Pumpsets	1.75	597
Rural Lighting	1.53	475
Industrial Energy Manage't	0.11	60
New HT Customers	0.30	161
Industrial Audit and Info'n	0.26	100
Industrial Motor Drives	0.28	108
Industrial Cogeneration	1.34	806
Municipal Lighting (Fluor.)	0.14	48
Municipal Lighting (SV)	0.04	22
Comm'l Lighting (Fluor.)	1.32	493
Comm'l Lighting (CLF)	0.36	266
Fluor. Lamp Standards	0.00	1007
TOTAL	18.83	8115

Source: Andhra Pradesh Case Study, ASCI Consultancy, 1998.

The Effect on Demand

The assumptions made about the impact of the DSM programme on consumption (GWh) and demand (MW) are summarised in *Table 2.64*. It is assumed for the load forecast that drives the power system expansion plan that the DSM measures contribute to a reduction in peak demand in proportion to the reduction in consumption. This will not be true, but no more accurate assessment was made.

The DSM programme lasts for ten years. The initial effect on demand is modest; it builds up over the ten year period and has a maximum effect in about 2006/7, when consumption is reduced by some 11%. Afterwards, savings decline as the DSM programmes expire. At the end of the period, demand in the DSM scenario is only 6% less than in BAU. This is a conservative approach that assumes the subsequent behaviour of consumers is not influenced by their introduction to efficient technologies. This is unlikely; it is probable that consumers would continue to adopt improved technologies after the programmes had expired, so the benefits of DSM are understated.

Table 2.64 Impacts of the DSM Measures on Demand

	1996/7	2001/2	2006/7	2011/2	2014/5
IFS					
(TWh)	37.6	48.4	70.9	106.2	135.3
(MW)	6340	7867	11132	16120	20144
DSM					
(TWh)	37.6	46.2	62.9	97.4	127.8
(MW)	6340	7513	9870	14789	19022
Saving					
(TWh)		2.2	8.0	8.8	7.5
(MW)		354	1262	1331	1122
(%)		4.5	11.3	8.3	5.6

Source: Andhra Pradesh Case Study, ASCI Consultancy, 1998.

The present value of capital expenditure for the DSM is 18bn Rs. At the peak the reduction in demand is 1331 MW. If the present value of costs is divided by the present value of the increments of generating capacity saved each year then the equivalent capital cost of the capacity saved by DSM is about $900 per kW or about 0.45Rs/kWh (0.013$/kWh). This is of the same order of magnitude as conventional power options, but the DSM has no fuel cost.

The Implications for the Environment

The attributes of this scenario are given in *Table 2.65*. Compared to IFS, the DSM scenario has a significantly lower cost and a significantly lower environmental impact as measured by every attribute. It is therefore a win-win strategy in every respect, if it can be implemented.

Table 2.65 ***Environmental Attributes of the DSM and IFS Scenarios for Andhra Pradesh***

Attribute	DSM	IFS
PV of cost (bn Rs)	692	742
PV of SO2 (kt)	2321	2552
PV of NOx (kt)	2354	2576
PV of TSP (kt)	228	252
Cumulative CO2 (mt)	1115	1235
Cumulative Ash (mt)	223	251
Land Use (ha)	1784	2008

Source: Andhra Pradesh Case Study, ASCI Consultancy, 1998.

The Reforms scenario resembles the DSM scenario in the present value of cost and the cumulative emissions of carbon dioxide. It is tempting to conclude from this similarity that the two scenarios describe different ways of achieving the same end, one by raising prices to reduce demand and promote efficiency and one by policy induced change of equipment and practice. There are several reasons why this deduction does not hold in detail.

The Reforms scenario assumes in principle a different economic framework from that of IFS and DSM. In practice, the prices of fuel and capital taken for the two scenarios are identical, although the Reforms scenario does model the IPP contracts and therefore has them running on base-load at high (economic) costs. The main difference is that the Reforms scenario does not include the user costs of the efficient appliances bought as a consequence of price rises. Another important difference is that the Reforms scenario only envisages price rises in agriculture and residential use, so that efficiencies in the industrial and commercial sectors from DSM are not captured in Reforms.

The two results are therefore not comparable in detail. Taken together they confirm that large cost-savings and environmental benefits are simultaneously achievable by actions on demand. The set of actions implicit in each of the two scenarios overlap to an extent, but not completely. Each of them separately therefore underestimates the potential. The chief distinguishing feature of the two approaches is the means by which demand is influenced and the practicality of implementation.

2.5.3 *The Evidence from Bihar*

Two DSM scenarios were run for Bihar. A smaller range of options for DSM were initially considered in the Bihar case-study than in Andhra Pradesh. This was done on the grounds that implementation of DSM in Bihar might be difficult. The options retained were:

- metering of agricultural pump-sets;
- installation of high efficiency pump-sets;
- promotion of high efficiency refrigerators.

At present, private tube-wells pay a flat rate of 30 Rs. Per/horse power per month. State schemes pay 120 Rs. Other studies indicate that if consumers pay the same amount as a unit charge then consumption typically falls by 15%. The estimate of savings in Bihar makes practical assumptions about the coincidence of operation of sets, of the rate of penetration of metering and of the size distribution of pumps. The study concludes that by saving electricity in agriculture and passing it on to industrial consumers the BSEB would benefit even if it bore the whole costs of the programme and did not increase its realisation from the agricultural consumers.

The programme for the installation of high efficiency pump-sets assumes that the manufacturer leases the sets to farmers, obtaining substantial tax credits for depreciation. The farmer pays half the cost of the lease; the utility pays the other half and recovers the money by selling the saved electricity on to industry at a higher price than it achieves in agriculture.

The programme for the sale of high efficiency refrigerators depends on sales promotions and labelling; after five years all new refrigerators are assumed to meet an acceptable standard. The costs and energy savings associated with these three programmes are summarised in *Table 2.66*.

Table 2.66 Summary of the DSM Programme in Bihar

	2001	2006	2011	2016
Metering of Pumpsets				
Participants (000)	19.7	32.4	51.2	72.5
Energy Saving (GWh)	7.1	11.6	18.4	26.1
High Efficiency Pumpsets				
Participants (000)	15.5	38.1	51.1	60.6
Energy Saving (GWh)	14.8	36.6	49.0	58.1
High Efficiency Refrigerators				
Participants (000)	119	681	1460	2124
Energy Saving (GWh)	21.9	125	267	339
TOTAL SAVING (GWh)	44	173	335	423

Source: Bihar Case Study, SCADA, 1998.

The total cost of this programme is estimated at around Rs 800 million; it could save some 250-300 MW of capacity by 2014. If present value of costs is divided by the present value of the incremental MW savings then the equivalent cost of DSM measures is around $300/kW. This is less than in Andhra Pradesh. The difference in cost reflects a more optimistic assumption in Bihar about the extent to which the measures will contribute to reducing peak demand. The impacts on demand of DSM measuring are shown in *Table 2.67* as below.

Table 2.67 Impacts of the DSM Measures on Demand in Bihar

	1996/7	2001/2	2006/7	2011/2	2014/5
IFS					
(TWh)	11.6	14.52	18.84	25.56	30.89
(MW)	2252	2873	3804	5283	6479
DSM					
(TWh)	11.6	14.48	18.66	25.24	30.46
(MW)	2252	2802	3653	5054	6203
Saving					
(TWh)		0.04	0.17	0.33	0.42
(MW)		71	151	229	276
Saving (%)					
(TWh)		.3	1.0	1.3	1.4
(MW)		2.5	4.0	4.3	4.3

Source: Bihar Case Study, SCADA, 1998.

A second DSM scenario, called DSM (EP) was then adopted that was designed to capture the full economic potential of DSM in the State. It was created by taking the supply curve for DSM calculated for Andhra Pradesh and scaling it to the situation of Bihar. This led to much larger savings and to much more significant reductions in environmental attributes.

A comparison of the environmental attributes for the DSM, DSM (Economic Potential) and IFS scenarios is given in *Table 2.68*.

The comparison shows that the full economic potential of DSM would reduce environmental attributes by some 5-6%. It reduces the present value of costs by 6.5%. This is broadly similar to the findings in Andhra Pradesh.

Table 2.68 Environmental Attributes of the DSM and IFS Scenarios for Bihar

Attribute	IFS	DSM	DSM (EP)
PV of cost (bn Rs)	198.1	196.4	185.7
PV of SO2 (kt)	913	910	864
PV of NOx (kt)	732	731	703
PV of TSP (kt)	60.3	59.9	56.6
PV of CO2 (mt)	141	140	133
PV of ash (mt)	37	37	35

Source: Bihar Case Study, SCADA, 1998.

2.5.4 *The Evidence from Other Studies in India and Elsewhere*

A thorough investigation of DSM potential in India was made by the Canadian Energy Research Institute and Tata Energy Research Institute ("Planning for the Indian Power Sector - Environmental and Development Considerations", Study No. 62, June 1995). Estimates of the potential for energy efficiency were based on the Indian power sector in 1990/1. All measures which could both replace capacity at under 30,000 Rs/kW (the capital cost of new coal-fired plant) and replace electricity at costs of less than 1.06 Rs/kWh (LRMC = 1.73-2.02 Rs/kWh) are considered to be cost-effective. The results are presented in terms of energy saved only. The potential savings are shown in *Table 2.69*, together with the results for Andhra Pradesh and Bihar. The savings identified are of the same order; exact comparison is not possible due to differences in time-frames, regional coverage, DSM measures considered and assumptions regarding the penetration of DSM technologies.

Table 2.69 Comparison of Estimated DSM Electricity Savings (%)

Study	2001/02	2006/7	2011/12	2014/15
Andhra Pradesh	4.5	11.3	8.3	5.6
Bihar (DSM (EP))	2.1	7.0	8.1	9.8
CERI	7.41	7.70	8.21	-

A study "Environmentally Sound Energy Efficient strategies: a case study of the Power Sector in India" was conducted by the Indira Gandhi Institute of Development Research (IGIDR), in collaboration with UNEP Collaborating Centre for Energy and

Environment, Riso National Laboratory, Denmark. The study considered DSM for High Tension industries in the State of Maharashtra; these HT industries accounted for 31% of electricity demand in 1992/3 and 38% of peak demand. Twelve separate DSM techniques were analysed, from lighting and motors to co-generation and time of day (TOD) tariff setting.

It was found that payback periods could be reduced to 0.5-2.4 years if an active DSM programme were implemented: the major reason for this reduction is that utilities were assumed to accept discount rates of 14% whereas typical customer discount rates were 25%. *Table 2.70* summarises a 5-year DSM plan for Maharashtra State. With all the identified options, demand savings of 760 MW and electricity savings of 8590 GWh are possible at the end of the 5 year period. The cost of saved demand for the utility is Rs. 4500/kW, with overall costs (including DSM participant costs) calculated at Rs. 15900/kW. Average costs of electricity savings are 0.78 Rs./kWh, with a maximum of 1.05 Rs./kWh for variable speed drives.

Generating capacity in Maharashtra in 1994 was 9340 MW and 41410 GWh of electricity were generated. The implementation of the 5-year DSM plan developed by the Maharashtra SEB could save 7-9% of capacity and up to 20% of demand. Considering strict energy efficiency measures only, capacity savings are of the order of 2% and demand savings are of the order of 8%. These figures are comparable to the results from the studies in Andhra Pradesh and Bihar.

Table 2.70 Five-year DSM Plan for Maharashtra SEB - Summary of Results

DSM Option	Demand Savings (MW)	Demand Savings (GWh)	Programme Cost (Rs million)	Utility Costs (Rs/kW)	CSE (Rs/kWh)	Total Costs (Rs/kW)
Time of Day Tariffs	160	-	376	1700	-	2100
Energy Eff'iency Measures	219	3380	1447	2000-12400	-0.1-1.05	6300-41100
Power Factor	58	-	78.1	800	-	3200
COGEN	323	5212	2328	4800	0.76	19100
TOTAL	760	8592	4229	4500	0.78	15900

A study on the DSM potential in Nepal was presented in a paper "Electricity planning with DSM in Nepal" (Energy Policy 1993 Vol. 21 No.7). Although over 95% of Nepalese electricity is supplied from hydro plant, the study provides a useful indication of the potential for DSM in rural areas with low levels of economic development. Only two DSM measures were considered: incandescent lighting and clay heater replacement. Five combinations of these measures with varying assumptions regarding their penetration rates were considered. It projects that by 2010 DSM using solely these measures could be responsible for savings of between 3 - 20% of electrical capacity and 2-12% of electrical demand. DSM also delays the planned building of new capacity.

2.5.5 *The Implications for All-India*

A study of the DSM potential in India was commissioned as a part of this Environmental Issues in the Power Sector project. It considered a selection of energy efficiency technologies of a kind that were suitable for DSM mechanisms. The findings in terms of the saving in peak demand and energy are summarised in *Table 2.71.*

Table 2.71 Estimates of Savings from DSM Programmes in India.

	Savings in Energy (TWh)	Savings in Peak(MW)	Indicative unit cost (Rs/kWh)
Industry			
Motor Drives	7.7	422	0.9
Cogeneration	32.1	5358	1.0
ToD tariff	-	6130	0
Agriculture			
HDPE pipes	6.2		0.4
Pump-sets	24.3		0.8
Domestic/Commercial			
Fluorescent Lighting	1.8	211	0.3
CFL Luminaires	2.6	300	1.2
Electronic chokes	0.2	195	2.6
Solar Water Heating	12.6	27	2.7
TOTAL	87.5	12643	

These savings are envisaged to be achieved over a ten year programme. The savings are therefore relevant to the energy and peak demands forecast for India at the end of the 10th Plan in 2007. The forecasts used by the CEA in the preparation of the Fourth National Power Plan are respectively 780 TWh and 130 GW. The estimates of the DSM potential therefore represent roughly 10% of load, broadly consistent with the Andhra Pradesh study.

The cost of each DSM measure is indicated in the table above. All the measures identified are cost-effective except for electronic chokes and solar water heating, where the economics are marginal. Low agricultural and retail tariffs will inhibit the spontaneous adoption of these measures. Financial packages can be designed so that both the utility and the customer benefits whilst prices remain below cost. These packages are complex to implement and beyond the capacities of SEBs that cannot currently collect their own debts.

2.5.6 *Conclusions*

DSM can be a cost-effective option that has beneficial environmental consequences. Implementation depends upon effective management in the SEBs.

There are ways in which reform will conflict with DSM and ways in which it will be complimentary. Reform will weaken the financial incentive for SEBs to participate. On the other hand, reform will provide a price incentive to users to co-operate in DSM. Complex financial packages can be devised that can make DSM attractive to consumers even if prices are low, but it is more straightforward and compelling if the DSM programme is backed up by proper price signals.

Reform can also be expected to strengthen the finances and management of the SEBs. This will improve their ability to deliver DSM programmes.

The full impact of DSM, that is unlikely to be achievable in practice, would reduce the environmental impacts by around 10% by 2014/5.

2.6 *WHAT ARE THE BENEFITS OF REHABILITATING T&D AND GENERATING PLANT?*

Transmission and distribution networks in India have high rates of technical and non-technical losses. Some of the generating plant is in poor condition and makes a disproportionate impact on the environment. This section examines the costs and environmental benefits of rehabilitating transmission and distribution networks for electricity and existing generating plant.

The benefits of rehabilitating T&D networks are assessed through a T&D scenario that explores the consequences for the environment of rehabilitating T&D networks in such a manner as to bring the losses in the networks down to levels that have been achieved elsewhere. It poses three subsidiary questions:

- how rapidly and how much could networks be upgraded?
- what would it cost?
- what are the consequences for the environment?

Estimating the benefits of rehabilitating old generating plant are less susceptible to the scenario approach as the decision has to be carried out on a plant by plant basis and the results will vary a lot from state to State. Estimates have been made for Bihar where there are many old and polluting plant and these are reported here.

2.6.1 *The T&D Scenario*

Losses in transmission and distribution during 1994/95 are estimated by the CEA at 21%, but most State level studies estimate them to be higher. The high losses are attributed to:

- weak transmission and distribution lines
- long transmission and distribution lines
- low power factor operation
- too many transformation stages
- pilferage and theft

A lack of financial resources and a focus on meeting demand for generating capacity have aggravated these problems.

The T&D loss reduction scenario assesses the costs and environmental consequences of bringing T&D losses to levels that should be realistically achievable on such systems. Technical and non-technical losses are assumed to reduce from the 19% estimated in the main BAU case to around 10% by 2010. These improvements arise because of the commercial motivation that leads to improved maintenance, metering, monitoring, billing and collection and the availability of more money for these purposes. ADB countries in 1990 had average T&D losses of 16.5%, with a large variation between countries. The best performers were Singapore (9.1%) and the Republic of Korea (10.2%), with China having an average for the Six Networks of 12.9%. This has been adopted as a suitable target for India by the end of the period.

2.6.2 *The Evidence from Andhra Pradesh*

T&D losses in Andhra Pradesh are taken to fall from 20% to 10% by 2010. The percentage loss rate is assumed to reduce by 1% a year for five years and 0.5% per year for the ten following years. The present value of the total costs of this scenario are estimated at 7 bn Rs. The basis for this calculation is the historical experience of APSEB that T&D savings cost one third of generation. When the new demand profile is entered into the power system and the system re-optimised there is a reduction in the present value of costs by nearly Rs 30 bn. The programme is therefore cost-effective. Reduction of T&D losses inevitably reduces all environmental attributes as is shown in *Table* 2.72.

Table 2.72 ***Environmental Attributes of the T&D and IFS Scenarios for Andhra Pradesh***

Attribute	T&D	IFS
PV of cost (bn Rs)	713	742
PV of SO2 (kt)	2469	2552
PV of NOx (kt)	2502	2576
PV of TSP (kt)	244	252
Cumulative CO2 (mt)	1189	1235
Cumulative Ash (mt)	242	251
Land Use (ha)	1936	2008

Source: Andhra Pradesh Case Study, ASCI Consultancy, 1998.

2.6.3 *The Evidence from Bihar*

The T&D loss reduction programme proposed for Bihar is based upon a detailed analysis of the present loss rates to various classes of consumers at different voltage levels. Agricultural non-technical losses are two-thirds but will reduce over the period. Overall, technical losses will fall from 28% in 1996 to 18% in 2015.

The cost of a programme of rehabilitation that would achieve these levels of loss has been estimated by comparison with detailed studies carried out in Haryana. These analyses suggested that 10 Rs of investment in rehabilitation of T&D save 1 kWh per year. On this basis the present value of the costs of the programme in Bihar were estimated at Rs 7 bn.

The power system expansion analysis shows that these reductions in losses would save Rs 9 bn in the present worth of capital expenditure on power plant and a little less than Rs 4 bn in present worth of operating costs. The investment figures are close to those of Andhra Pradesh; this is fortuitous, but reflects the poorer condition of the smaller system in Bihar. The savings in Bihar are less because of the load shedding (in the early years) and associated lower load factors on lines. The programme is still very cost effective.

Rehabilitation of Power Plant

The Government of Bihar in 1996 commissioned a study of the restructuring of the power sector in Bihar. As a part of this work a programme of technical recommendations were developed to rehabilitate the existing power plant. (Power Sector Restructuring Synopsis Report, International Resources Group, July 1996).

The rehabilitation measures for existing plant, as recommended in this report, have been included in a variant IFS scenario that combines plant rehabilitation with rehabilitation of the T&D system. The costs and performance benefits of this rehabilitation are summarised in Box 2.1.

Box 2.1 Costs and performance benefits of rehabilitation

Emergency Measures

Station	Additional Power (MW)	Capital Cost (M Rs)	Unit Cost (MRs/MW)
PTPS	80	211	2.6
BTPS	23	75	3.3
MTPS	13	44	3.4
SHPS	-	10	
KHPS	12	33	2.79
TOTAL	128	374	2.92

plf improves by 40%

Medium and Long-Term Measures

Station	Additional Power (MW)	Capital Cost (M Rs)	Unit Cost (MRs/MW)
PTPS	80	1789	22.4
BTPS	24	841	35.0
MTPS	20	197	9.8
SHPS	2	62	31.0
KHPS	12		
TOTAL	126	2888	22.9

plf improves by 60%

Costs in this scenario fall because of the much improved efficiency of the plant, but the environmental attributes all increase. This is because the poor state of the system at present means that much load is not met and the rehabilitated plants are able to supply more electricity, with associated environmental impacts.

Table 2.73 compares the attributes of the three scenarios.

Table 2.73 Environmental Attributes of the T&D and IFS Scenarios for Bihar

Attribute	IFS	T&D	T&D + Plant Rehab
PV of cost (bn Rs)	198.1	185.7	175.8
PV of SO2 (kt)	913	860	862
PV of NOx (kt)	732	694	696
PV of TSP (kt)	60.3	56.0	56.7
PV of CO2 (mt)	141	132	132
PV of ash (mt)	36.7	35.2	35.5

Source: Bihar Case Study, SCADA, 1998.

2.7 *HOW MUCH WOULD CLEAN COAL AND COAL WASHING ACHIEVE?*

There is a variety of new technologies for burning coal that can have environmental benefits. The costs tend to be higher than conventional plant and the performance is not fully proven in commercial application. Over the study period it is likely that clean coal technologies will be adopted and so the work has analysed the costs and environmental consequences. The analysis has been performed by a scenario approach; it poses four subsidiary questions:

- what are the likely costs and performance of clean coal technology in the medium term?
- under what conditions are the new technologies selected?
- what are the consequences for the environment?

Indian coal has a high ash content and ash disposal is one of the most pressing environmental problems. Washing coal to remove some of the mineral matter is widely practised in other countries but is not much done in India. The costs and benefits of extending this practice in India are examined through a separate cost-benefit analysis. This approach was preferred to the scenario approach for this topic because many factors influence the conclusion and the interaction of these factors is easier to study outside of a least cost planning model.

2.7.1 *The Coal Technology Scenario*

The Coal Technology scenario explores the consequences of clean coal technologies and their relevance to the Indian situation. There are several new technologies that might be considered. A preliminary screening of several technologies was made and compared to conventional pulverised fuel technology and to pulverised fuel supplemented by low NOx burners and FGD. Under most reasonable assumptions about the future cost of coal, the clean coal technologies on base load have levelised costs of generation about 10 -15 % higher than conventional plant.

Because there is little experience of these new technologies at a commercial scale, there is still much uncertainty about how much they cost and how well they will perform. The new technologies are mainly base load plant competing among themselves for the base load function. If they were all to be entered into the power system planning model then only the one with the lowest levelised cost at base load would be chosen. There is little point therefore in presenting them all to the model. For this reason one technology was chosen in each Case Study as a proxy for all clean coal technologies. In each Case Study a different proxy was chosen reflecting the different circumstances of each State.

A comprehensive review of clean coal technologies for developing countries was undertaken for the World Bank in 1995 (1) . This has been the principal basis for the performance characteristics and costs assumed for the analysis. There is generally no experience of these plants at commercial scale so the data is uncertain. Box 2.2 summarises the performance characteristics for clean coal established by this study.

2.7.2 *The Evidence from Andhra Pradesh*

In Andhra Pradesh, Pressurised Fluidised Bed Combustion (PFBC) technology is used as a proxy for clean coal technology. The new technology has to be forced into the expansion plan; the extra capital cost causes the present value of the total cost of the scenario to rise by some 14 bn Rs compared to IFS, (about 2%), but the scenario gives reduced environmental impacts for the period attributes of ash (down 2%), TSP (down 3%), CO2 (down 3%), NOx (down 10%) and SOx (down 15%). The attributes are summarised in *Table 2.74*.

Table 2.75 shows the plant efficiencies estimated within this study. The wide range of estimates indicates the uncertainty referred to above. The main improvement is in emissions of NOx and SOx because they can be easily removed in the pressurised environment. There is a small fall in CO2 , TSP and ash because of the improved thermal efficiency.

(1) Tavoulareas ES and Charpentier, J. (1995) Clean Coal Technologies for Developing Countries. World Bank Technical Paper 238: Energy Series: Washington DC..

Box 2.2 Characteristics of Clean Coal Technologies

Technology	% SO_2 removal	% NO_x removal	Particulate removal	Capital Costs (USS/kW) New Plants	Retrofits
Physical Coal Cleaning	10-40	None	30-60% lower fly ash	1-5 USS/ton of coal	1-5 USS/ton of coal
Advance Coal Cleaning	30-70	None	Up to 70% lower fly ash	5-20 USS/ton of coal	5-20 USS/ton of coal
Low NO_x Combustion	None	30-60	None	2-10	5-25
Sorbent injection	30-60	None	None	50-80	70-100
Duct injection					
Pre-ESP	30-70	None	None	50-100	60-120
Post- ESP	70-90	None	None	80-170	100-200
Wet FGD	90-99	None	% depends on ESP-FGD Configuration	120-210	150-270
Dry FGD	70-90	None	None	110-165	140-210
SNCR	None	35-60	None	5-10	10-30
SCR	None	70-90	None	50-100	50-150
Combined SO_x/NO_x	80-95	80-90	Possible by some technologies	300-400	300-400
Advanced ESP	None	None	Up to 99.9%	40-100	40-100
Bagfilters	None	None	Up to 99.9%	50-70	50-70
Hot-gas cleanup	None	None	Up to 99.9%	Not available	Not available
AFBC	70-95	50-80	None	1300-1600	500-1000
PFBC	80-95	50-80	None	1200-1500	Not available
IGCC	90-99.9	60-90	None	1500-1800	Not available

Note: Advanced coal cleaning includes advanced physical, chemical and biological cleaning methods. **ESP** = electrostatic precipitator; **FGD** = flue-gas desulfurisation; **SNCR** = selective non-catalytic reduction; **SCR** = selective catalytic reduction; **AFBC** = atmospheric fluidised bed combustion; **PFBC** = pressurised fluidised-bed combustion; **IGCC** = integrated gasification combined cycle. The reference plant is conventional pulverised fuel coal-fired power plant.

Table 2.74 Environmental Attributes of the New Tech and IFS Scenarios for Andhra Pradesh

Attribute	New Tech	IFS
PV of cost (bn Rs)	756	742
PV of SO2 (kt)	2160	2552
PV of NOx (kt)	2323	2576
PV of TSP (kt)	245	252
Cumulative CO2 (mt)	1193	1235
Cumulative Ash (mt)	246	251
Land Use (ha)	1968	2008

Source: Andhra Pradesh Case Study, ASCI Consultancy, 1998.

Table 2.75 Clean Coal Technologies

Technology and Plant Efficiency	
Technology	**Plant Efficiency (% LHV)**
Pulverised Coal with electrostatic precipitator (reference technology)	35-38
Pulverised Coal with wet flue-gas desulfurisation	34-37
Atmospheric fluidised-bed combustion	35-38
Pressurised fluidised-bed combustion	38-45
Integrated gasification combined cycle	38-45

2.7.3 *The Evidence from Bihar*

In Bihar the new technology chosen as a proxy for clean coal technology is the integrated gasification combined cycle plant (IGCC). All the candidate plants in the power system expansion model were assumed to be converted to IGCC or newly built to that design. As shown in *Table 2.76*, the present value of the total cost of the scenario rises by some 4 bn Rs compared to IFS, (about 2%), but the scenario gives the lowest environmental impacts for the period from TSP (down 17%), NOx (down 8%) and SO_2 (down 17%). The bigger benefits for SO_2 and TSP and the higher cost are because gasification is chosen to represent clean technology. Ash, however, increases slightly.

Table 2.76 Environmental Attributes of the New Tech and IFS Scenarios for Bihar

Attribute	New Tech	IFS
PV of cost (bn Rs)	202	198.1
PV of SO2 (kt)	754	913
PV of NOx (kt)	676	732
PV of TSP (kt)	50	60.3
PV of CO2 (mt)	135	141
PV of Ash (mt)	37.0	36.7

Source: Bihar Case Study, SCADA, 1998.

There are some interesting differences from the PFBC technology. There is still a marked improvement in emissions of oxides of nitrogen and sulphur because of the ability to remove them in the gasifier. There is a small improvement in CO2 because of the improved thermal efficiency, but rather a large improvement in TSP as the emissions are contained by the gasification process.

2.7.4 *Implications for all-India*

The Canadian Energy Research Institute (CERI) in conjunction with the Tata Energy Research Institute (TERI) undertook a major study of the environmental and development considerations pertinent to the planning of the Indian power sector.

This study concluded that fluidised-bed combustors were the best alternative to pulverised coal boilers in the medium term. The study detected an "urgent need to immediately" introduce 100 MW units in India to gain operating experience.

The study also recommended that IGCC systems should be installed in an increasing percentage of the added capacity and all retro-fit and renovations of existing capacity. By the turn of the century the share of IGCC systems might reach 5000 MW.

These are ambitious targets and given the small extent of commercial experience, such a programme would be high risk. The present analysis in Andhra Pradesh and Bihar suggests that the programme would not be least cost. There might be a case for seeking funding from the Global Environmental Facility (GEF) for an initiative in this area, although the benefits are mostly local, CO_2 reduction is fairly small, and there may be more cost-effective options.

2.7.5 *Coal Washing*

A comprehensive review of Coal Beneficiation was prepared by ASCI Consultancy for this work; it is the main source for this section.

Introduction

The contribution of open-cast mining to coal production in India has increased steadily from around 20% in 1970/71 to 73% in 1995/96. Partly as a consequence of this shift, there has been a fall in the calorific value of the coal mined and an increase in the ash content. The average calorific value has fallen from 5900 kcal/kg in 19660/61 to 3500 kcal/kg in 1995/96; a very marked deterioration.

High ash content in coal has environmental consequences. Inevitably, there is more ash to dispose of at the power station site and the high particulate loadings in the flue gases either increase the emissions of TSP or incur higher costs in control. There are also economic consequences. The mineral matter in the coal has to be transported to the power station site and this incurs transport costs; the minerals increase the rate of wear of coal crushing equipment and of the combustion plant. Plants that are to burn the high ash coal are intrinsically more expensive and less efficient because they must handle large quantities of non-combustible and abrasive matter.

The advantages of removing mineral matter at the mine are numerous and the economic advantages appear attractive. Experience elsewhere in the world where coal washing is widely practised would bear this out. But there are costs in washing coal, there are environmental problems and Indian coal has some characteristics that affect the costs and benefits.

Experience in India

Two large capacity plants have been located at the important coalfields in Talcher and North Karanpura. The Piparwar project on the North Karanpura field was commissioned in March, 1997; it is linked to the power station at Dadri. It is already in operation and regular supplies of washed coal are expected from the end of 1997. The Kalinga plant on the Talcher coalfield is under construction and is expected to be commissioned by March, 2000.

The expected characteristics of these plants are resumed in *Table 2.77.*

It is also proposed to supply 4 mtpa of beneficiated coal to the power plant at Vishakhapatnam from the Bharatpur and Ananta open cast coal mines on the Talcher coal field. The run-of-the-mine coal is expected to have an ash content of around 40% and moisture of 6%. The clean coal should have 34% ash and 6.5% moisture; the yield is estimated at 76-77%. A plant of 4.5 mtpa is being constructed on the Singrauli field. The Bombay Suburban Electric Supply Ltd have set up a power station of 500MW about 120 km north of Mumbai. The coal is transported 1400 km. A coal washery is planned with a capacity of 2 mt to reduce the ash content from 38-40% down to 30%. The expected yield is 83%. The cost of the process is estimated at 125 Rs/tonne.

Table 2.77 Characteristics of Coal Washing Plants

	Kalinga		Piparwar	
	Run of Mine	Cleaned	Run of Mine	Cleaned
Grade of Coal	F	F	G	G
Ash (%)	41	34	47	34
Moisture (%)	6	7	7	8
GCV (kcal/kg)	4041	4582	3279	4422
Recovery (%)	74		85	
Capital Cost (bn Rs)	3.45		4.62	
Throughput (mtpa)	8	5.9	6.5	5.5
Unit Investment (Rs/tpa)	4.3		7.1	
Levelised cost at 12% (Rs/t)	101		151	
Employment	1440		660	

Source: Energy Division, Planning Commission.

Economics of Coal Washing

The economics of coal washing are controversial because they depend on many factors for which there is little reliable experience. Essentially the cost-benefit analysis is a balance of the costs of washing (including the environmental cost) and the benefits of improved power plant performance, reduction in transportation and the environmental benefits at the power plant.

Indian non-coking coals are difficult to wash because the mineral matter is intimately included in the coal matrix and is not extraneous. The proportion of near gravity materials is high. Washing is therefore expensive and a significant proportion of the carbon is lost. The *Table 2.77* shows that 15-25% of the coal is lost in washing. The environmental problems at washeries can be severe. Not only is there a large volume of solid material to dispose of, but much of it is in fine carbon particles suspended in water. Poorly functioning washeries can be the source of very severe water pollution. The additional requirement of coal mining and the loss of carboniferous material results in a higher overall requirement for the disposal of solid wastes. A detailed study of a 1890 MW coal plant suggests that reducing the ash content to 30% would require a 300 hectare area for dumping the tailings, but save only 80 hectares at the mine.

Because of these considerations, the cost of washing coal is between 20-30% of the cost of mining it. There are benefits in the combustion process, but their magnitude is controversial. It has been observed that several power stations that use unwashed coal still achieve some of the highest availabilities in the country (e.g. Vijayawada and

Orissa). The savings in transportation from lower ash are partially off-set by the higher moisture content.

An analysis made within the context of the Andhra Pradesh Case Study, based on a comprehensive review of available data, concluded that:

- washing of coal with marginally high ash content (30-38%) or with calorific values greater than 4000 kcal/kg may not be advantageous,
- for high ash, low calorific value transported over distances of 1000 km or more, washing can be economically viable.

Alternatively the formula used earlier to calculate the economic price differentials for different grades of coal in *Table 2.31* can be used to calculate the added value brought about by washing. These come to 175 Rs/tonne at Kalinga and 353 Rs / tonne at Piparwar. The benefits calculated on this basis far exceed the costs.

The largest part of the benefit from higher quality arises from the lower capital cost of the power plant designed to burn the better quality of fuel. The largest benefits can therefore only be achieved in new plant designed for washed coal. Moreover, the designer must be confident that the coal for which the plant is designed will actually be delivered consistently to the plant. It may therefore be advantageous to consider requiring all new coal-fired plants to burn washed coal.

2.8 *CAN MORE ASH FROM POWER STATIONS BE UTILISED AND IF SO HOW?*

This scenario explores the consequences for the environment of ash utilisation. It poses the following subsidiary questions:

- what is the current ash production and utilisation in India?
- are the costs of ash disposal fully borne by the ash producers?
- what is the potential for ash utilisation in India?
- why is this potential not being realised?
- what are the lessons from other countries?
- what are the options for ash utilisation policy in India?

It draws on the Special Study on Ash Management, Disposal and Utilisation(1) commissioned by the World Bank as a part of this work, but also reviews much other material that has been produced on ash utilisation in India.

(1) Review of Coal Ash Utilisation, in Ash Management, Disposal and Utilisation, Water and Earth Science Associates, May 1996.

2.8.1 *The Current Situation in India*

Ash Production

Section 2.15 describes the current and expected production of ash from coal-fired power stations in India. In 1996/97 some 62 million tonnes was produced but the projections suggest that by the year 2014/15 the annual production will increase to over 180 million tonnes. Cumulatively over this period, some 2 billion tonnes of ash would be produced.

Of the current ash production, 22 million tonnes came from NTPC's thirteen coal fired power plants with a combined capacity of 14,600MW.

Technical Characteristics of Indian Ash

Coal ash is a complex material, variable in terms of specific gravity, size, morphology, microstructure and mineralogy. The ash produced from coals in India (with some exceptions such as the lignites from the Neyveli mines in Tamil Nadu) has a low content of calcium that limits its value for the manufacture of construction materials. Indian fly ashes exhibit a wide range of characteristics, partly because of the varying characteristics of Indian coals and partly because of the lack of standardisation in the techniques of ash collection and disposal. Indian ashes tend to be less reactive and require higher water content to achieve acceptable workability of cement and concrete.

Current Ash Utilisation

About 2-3% of the production of coal ash in India is used. This is less than in most other large ash producing countries. 10% of ash was utilised by NTPC in recent years in contrast to the low overall national utilisation and suggests that almost no ash is utilised by SEBs(1). There is no information on the overall utilisation of ash in India but *Table 2.78* below presents the breakdown of ash utilisation at the NTPC's thermal power stations.

Central Level Official Indian Initiatives

The National government provides some fiscal incentives. Bricks and other building materials using 25% or more fly ash as raw material are exempt from excise duty. Import of machinery necessary for the production of building materials from ash is exempt from customs duty if it is not indigenously available. The National government has also taken various administrative actions:

(1) Trehan, A., Krishnamurthy, R. and Kumar, A. NTPC's Experience in Ash Utilisation, Indo European Seminar, 1997

- State governments have been asked to prepare action plans for using 50% of fly ash by the year 2000.
- SPCBs have been asked to be lenient with industries using industrial wastes.
- Environmental clearances to thermal power plants emphasise the need to arrange for dry ash collection and fly ash utilisation.
-

Table 2.78 Annual Ash Utilisation at NTPC

Utilisation	Quantity of ash utilised in 1995-96 in '000 t	Quantity of ash utilised in 1996-97 in '000 t
Total ash generated at NTPC stations	20,000	20,200
Land development	530	400
Issue to industries	560	740
Dyke raising	820	950
Brick manufacturing	9	11
Road construction	15	57
Mine filling	32	37
Others	28	4
Total utilisation	1,994	2,200

NTPC Ash Utilisation Policy

The Ash Utilisation Division (AUD) of NTPC was established in 1991 at a corporate level and subsequently Ash Utilisation Cells were established at each power plant. The policy aimed to enhance ash utilisation through identification and adoption of appropriate technologies, setting up pilot projects and demonstration units and R&D activities.

To encourage fly ash utilisation, NTPC offers incentives to entrepreneurs to set up ash utilisation projects within the power plant boundary. These incentives include:

- the provision of dry fly ash free of cost to users in and around the power station for an initial period of five years;
- if NTPC has surplus land this may be made available to companies utilising ash and leased for a period of 15 years at a discounted rent;
- for other users supply of dry fly ash this is provided free of cost up to the year 2002; pond ash and bottom ash is provided free of cost on *as is where is basis;* and
- NTPC may invest equity in joint venture companies involved in ash utilisation.

NTPC promotes the utilisation of ash internally in its construction activities and in assisting private companies in using ash. This programme has been running for 6 years and has succeeded in increasing ash utilisation from 2-3% in 1991 to 10% (220,000 tonnes) in 1996/97. NTPC has introduced dry ash extraction and collection systems at the Dadri power station and has plans to extend this system to permit use of ash in cement and concrete industries. NTPC has signed MOUs for the use of 300,000 tonnes per year for ash in cement from Dadri and Unchahar power plants.

Initiatives at the State Level

The government of Orissa has announced a policy:

- to supply fly ash free to manufacturers of products;
- to allow free access to land and water for fly ash industries in the vicinity of power stations;
- of concessional power tariffs;
- of exemption from sales tax on the sale of bricks made from fly ash and of the purchase of manufacturing equipment;
- restrictions on the use of soil for manufacturing conventional bricks;
- obligations on government to use bricks made from fly ash in construction; and
- subsidies to producers for the installation of pollution control plants.

2.8.2 *Are the Costs of Ash Disposal in India Fully Borne by the Ash Producers?*

Ash Disposal and Management Practices in India

Fly ash has the potential to cause pollution of air and surface water and groundwater, adversely affecting land-use practices and public health. The flyash collected in ESP is normally sluiced with water to ash ponds for disposal. The ash settles in ponds and clean water is discharged into adjacent natural water bodies. In well-designed and managed ash disposal systems, the pollution is minimal. Current environmental standards imposed by CPCB are adequate.

In practice, at most power plants in India, ash ponds are not properly designed or operated and do not comply with CPCB standards. Large quantities of fly ash are transported to reservoirs, streams and rivers; the turbidity increases causing changes in the aquatic ecosystem. Some of the ash settles down causing siltation.

Dissolved ash releases toxic elements; part of the water from the ash pond leaches into the subsurface and mixes with the groundwater which also gets contaminated. In the ash ponds, areas of exposed ash are common and during dry periods, the wind blows away portions of exposed ash.

Large areas of land are necessary to store the ash and the land is essentially lost to its original use. Large expenditure are necessary to reclaim this land after the disposal operations are over, and this is seldom done.

The evidence from the Case Studies tends to support this assessment. The Andhra Pradesh study says "*The cumulative ash stock piling outside the thermal plants is a major environmental hazard. Only about 5% of the ash is taken away by the cement industries and some additional percentage by other industries. The rest of it is dumped either in ash ponds or simply left in a pile outside the plants*".

The Bihar Case Study has examined ash disposal problems at four power plants. At Barauni, there has been spillage of ash from the ash ponds to local agricultural land and the ash pond is located on permeable sand, allowing groundwater contamination. During the monsoon season, the Ganges river inundates the ash pond during some years for a period of 2 to 3 weeks. At Patratu , the ash ponds are located along two rivers. Some of the dykes are made of ash without soil cover. The rivers are said to be full of ash; during the dry seasons, there are significant fugitive dust emissions.

What Do Poor Ash Disposal Practices Suggest for Policy?

A justification for government intervention in support of ash utilisation is to avoid pollution. The economic justification is that the full costs of ash disposal are not borne by the producer and that intervention is required to correct this 'market failure'. In theory, the design of power plants includes full compliance with ash disposal standards. The external costs of the pollution of air and water are internalised largely, if not completely, through the control costs required to meet existing environmental standards. In practice the standards are often not met. If these standards are not met then it may be more appropriate to consider how to ensure compliance (ie measures for ash management) rather than changing policy on coal use or ash utilisation.

The costs of resettlement and rehabilitation are also, in principle, internalised. The cost of acquiring land appears in the project cost and there is provision for compensation for those affected otherwise than by loss of land. It may be that these provisions are inadequate, that enforcement is weak and that poor communities suffer because of asymmetric access to courts and the administration. If so, then the appropriate policy is to correct the failures in the process rather than to try to represent them as an external cost.

Even if standards are met, there may still be residual pollution and other impacts that are hard to avoid, such as noise, visual intrusion and disruption from vehicle movements. These external costs could justify internalisation through a tax on disposal. The UK government levies a tax of £2 ($3.5)/tonne on the disposal of ash to land-fill.

2.8.3 *The Potential for Ash Utilisation in India*

Value Added in Various Uses of Ash

Uses of ash can be classified according to the value added to the material. *Box 2.3* summarises uses according to this scheme. The *Box 2.4* indicates the economic sectors in which products can find a use.

Box 2.3 ***Uses of Ash Distinguished by Value***

Low Value	Medium Value	High Value
mine fill	light weight aggregate	metal recovery
embankments	concrete	mineral wool
back fill	pozzolana cement	plastic fillers
highway base	cellular concrete	ceramics
soil stabilisation	bricks	light weight refractories
structural fill	grouting	ferro-silicon
water dam concrete	slabs and wall panels	
harbour structures	building blocks	

Source: Kumar and Kher , NTPC's Ash Utilisation Programme - practical experiences, New Delhi, July, 1995.

In applications with high value added the choice among raw materials to use will be governed primarily by the quality of the finished product and will be relatively insensitive to price. The volumes required in the higher value applications also tend to be small. To a lesser extent similar tendencies hold for the medium value applications. If there is a significant environmental cost to the disposal of ash and if this cost were to be set against the costs of utilising the ash then it is the low value applications that may be most affected. These are also the applications where the largest volumes might be absorbed.

Though it is important to develop high value added applications of ash, it is the low value applications that will be most beneficial to the environment and that environmental measures are most likely to influence.

Box 2.4 *Applications of coal ash*

Agriculture: as an absorbent, artificial aggregate, fertiliser and soil conditioner.

Building Materials: for aggregate, bricks, building blocks, ceramic products, paving materials, roofing tiles, wallboards and panelling.

Cement and Concrete: in cement, cement extender, cement substitute, concrete, concrete filler , foamed concrete, mortar.

Civil engineering: aggregate, asphalt filler, back-fill, embankment materials, foundations and road construction, grout, hydraulic barriers.

Industrial materials: abrasives, absorbents, artificial sand and aggregate, ceramic materials, decorative materials, filter media, gas cleaning, industrial fillers.

Materials recovery: recovery of alumina, iron and silicon, trace elements.

Waste treatment: grout, waste stabilisation.

Source: Special Study on Coal Ash Utilisation

Uses for Ash in India at Present

Most practical activity in India so far has been directed to finding uses for coal ash in construction materials. The chronic shortage of housing in India and the strong demand for building materials encourages this quest. The projected shortage in materials in the 8th Plan is 17 million tonnes of cement and 50 billion bricks.

Many processes have been implemented in India, using different amounts of fly ash for each brick varying from 30-90% of the solid raw materials. In most cases it is necessary to add lime, sand or other binding reagents to the mixture of ash and clay to meet requirement standards. This adds to the cost of manufacture. The production of bricks from fly ash appears to be economic only when production exceeds 25-30,000 bricks per day and if the bricks are used within 50 km of the production site. A plant of this size would consume at most around 60 tonnes of ash per day or about the amount produced by a 200MW plant in one hour. A 200MW plant might produce enough ash to make 150 million bricks in a year compared, for example, to the annual demand of the West Bengal State Public Works Department for government buildings, hospitals, schools, etc., of 600 million bricks per year.

Indian Experience of Low Value Added Uses (1) (2) (3)

Technical standards have been prepared for using ash in civil engineering work, but apart from demonstration activities little has been accomplished. Costs of supplying ash to the construction site appear frequently to exceed the costs of using soil from the locality. Bituminous concrete comprises a mixture of aggregates with fillers and asphalt. Coal ash has excellent properties for use as a filler.

Fly ash can replace cement in many concretes and some buildings in India have been built with concrete containing ash. Fly ash concretes have also been used in bulk construction for dams and other large civil engineering projects.

Fly ash can be used to condition soil. Ash tends to be alkaline and can correct for low pH in soils. It can also increase the ability of heavy clay and light sandy soils to retain moisture and fertiliser. There are some 130 million hectares of waste land in India of which a substantial proportion is acidic. About 20-40 tonnes of fly ash per hectare is necessary for treatment so large volumes could be used for this. Again the transport costs of the ash are a significant impediment.

Constraints to the Use of Coal Ash in India

The *Review of Coal Ash Utilisation* undertaken as part of this study identifies several obstacles to restrict productive applications. Among them are:

- quality variations: the properties of coal ash can vary widely depending on the source of coal, the combustion process and how and where the ash is collected; these variations can feed through into variations in the quality of the finished products;
- wet collection and disposal; most power stations in India use wet methods to collect and dispose of coal ash, this makes the ash unfit to be used for concrete and cement; it also impedes transport of ash; the practice of mixing bottom-ash with fly ash also impairs quality;
- transportation costs: power stations in India are often located in remote areas and transportation costs can be significant;
- technological limitations: equipment for the higher value added processes is often not available in India and cannot be maintained;
- consumer resistance: consumers have doubts about the quality of products based on coal ash compared to traditional materials; little is done to overcome this by

(1) NTPC, Workshop on Ash Utilisation, August, 1994

(2) Kumar, V. Technological Developments for Safe Disposal and Utilisation of Fly Ashes in India, Indo-European Seminar, 1997

(3) Trehan, A., Krishnamurthy, R., and Kumar, A., NTPC's Experience in Ash Utilisation, Indo-European Seminar, 1997

promoting the alternatives; the promotional efforts that are made are directed mainly at the use of coal ash in bricks, concrete and cement and not in bulk applications.

The Economics of Ash Utilisation and Disposal

It is possible to examine the economics of ash utilisation as one or other of:

- the cost of ash disposal which the power station avoids if coal ash is used.
- the cost which industry would save by using ash rather than other materials? This is equivalent to the price which the power stations could ask for ash in a competitive market.

The economic value of a product is normally determined by the interaction of supply and demand. In India, because of the vast surplus of ash, the economic value is dictated by the avoided cost of ash disposal. Unlike countries which can sell ash, in India the generators should pay industry to utilise the ash.

Using the design specifications established in the report *Coal Ash Management in Thermal Power Plants,* (1) the levelised cost of ash disposal comes out at about $4.4/tonne of ash, at a discount rate of 12%. These calculations assume dry collection and dry disposal, with advanced pollution controls, handling 1.8 million tonnes of ash a year. The costs do not allow for land pre-emption nor directly for environmental and social costs. Indirectly many of the environmental costs are present as the control costs incorporated into the plant design. Social costs and the costs of land are probably the most important omissions from this figure.

We take a value of $6/tonne for the complete costs of disposal. The $6/tonne for ash disposal is intended to indicate the order of magnitude , not a specific value, in order to show how much the power companies should be willing to pay to encourage parties to utilise ash. Above $6/tonne it is cheaper for the power plant to build its own ash disposal facilities.

The Potential Quantities of Ash Utilisation

The potential utilisation of ash depends upon industry and in particular, upon:

- the price which industry must pay to the generators for the ash, plus the cost of transport,
- the cost of the alternative materials,
- the impact of using coal ash on the quality of the end product, and

(1) Water and Earth Science Associates, Coal Ash Management in Thermal Power Plants, in Ash Management, Disposal and Utilisation Study, May 1996

- the impact that using coal ash has on the cost of the production process.

These four factors in combination can be summarised as the value of coal ash to industry.

The cost of ash disposal is equivalent to about 0.2 Rs per kg. A brick manufactured from fly ash uses about 1.5 kg of ash, so the benefit per brick amounts to 0.3Rs. The total cost of a conventional brick is about 1 Rs per brick. If power generators offered to pay industry a price of 0.2 Rs per kg, this would be a significant benefit to the brick manufacturer (20% saving), but is not overwhelming compared to total production costs.

For low value added uses, the avoided disposal costs of $6/tonne are equivalent to the economic costs of transporting coal about 200 km by rail. (1) If the costs of transporting ash are comparable to the cost of transporting coal, the avoided costs of disposal would permit transporting ash some 200 km as an alternative to top soil for construction projects.

No detailed estimates are available of the potential utilisation of ash. This is a particularly serious omission given the current initiatives being taken to ensure high levels of utilisation. It is not obvious that realisation of these very high targets are in the economic interest of India and could over-burden the power industry with high costs. Nevertheless, it is also reasonably clear that the utilisation of ash at only 2-3% of the total is currently well below that achieved in many other countries (see below).

2.8.4 *Why is this Potential Not Being Realised?*

Though there are significant constraints to the utilisation of ash, there is a substantial potential utilisation which has not been realised. The principle reason for this is that the structure of the power sector does not provide incentives to thermal power plants to reduce costs. With sufficiently strong commercial incentives, power generators would pay industry to take the ash away providing that the amount they pay industry is below the cost of ash disposal in ash ponds.

A second reason for the lack of ash utilisation by the SEBs, may be that the poor compliance with environmental standards implies that the actual cost of ash disposal in Indian power plants is much lower than the costs in well designed and managed systems. The incentives in an industry facing severe financial shortfalls and weak enforcement of environmental standards, will therefore lead the SEBs to save money through poor ash pond management rather than to giving encouragement to industry to utilise the ash.

(1) TERI, Inter-Fuel Substitution Special Study, 1997

2.8.5 *Lessons from Other Countries*

Table 2.79 summarises how ash is used elsewhere.

Table 2.79 ***Use of Ash from Bituminous Coal in Other Countries***

Country	Annual Production of Ash (mt)	% of ash used	Applications
USA	63	29	Cement, concrete, fill.
China	55	25	Concrete, bricks, fill
Poland	24	17	Cement, concrete, fill
Germany	6	85	Building and in mining
UK	11	57	Cement, fill material, aerated concrete blocks.
South Africa	13	negligible	
Former Yugoslavia	12	5	Cement, bricks

Source: Special Study on Coal Ash Utilisation

2.8.6 *Recommendations for Technical Priorities in India*

The Special Study on ash utilisation recommends that low value added utilisation should be given top priority. The applications to be investigated in order of priority are:

- land reclamation/growth media for afforestation and agriculture;
- raising of plantations;
- embankment construction;
- road making; and
- industrial effluent treatment.

Medium value added applications that should be established in order of priority are:

- light weight aggregate;
- Portland cement clinkers;
- Portland pozzolana cement;
- ready to mix flyash concrete; and
- bricks/blocks.

2.8.7 *The Policy Options Available in India*

Conclusions from the above discussion suggest the following:

- The current problems of ash disposal and management could in part be corrected through stronger enforcement of present environmental standards.

- There are constraints to the utilisation of ash in India but the economic potential has not been fully realised.

The reason that the potential utilisation has not been realised are:

- The current structure of the power industry does not give incentives for power generators to reduce the costs of ash disposal.
- The financial constraints on SEBs do not allow them to give financial encouragement to industry to utilise ash.

Policy Options

There are three policy options which might be considered:

- Electricity sector reform and restructuring.
- Binding utilisation levels.
- A tax on ash disposal.

Sector Reform

Enforcement of standards for ash disposal will encourage SEBs to promote the utilisation of ash by industry. This, combined with improvements in the financial performance of SEBs could boost ash utilisation, leading to levels similar to that achieved by NTPC at present - approximately 10%.

Electricity sector reform combined with strict enforcement of environmental standards will boost ash utilisation. *Table 2.79* shows that in the UK with private sector power generators and no incentives other than commercial incentives, ash utilisation of 60% has been achieved.

Binding Targets

Binding targets imposed by central Government could be effective in achieving high levels of a utilisation. However, this policy, as with all 'command-and-control' policies could force power generators to establish ash utilisation schemes which are uneconomic. This would raise the cost of electricity generation.

In the absence of reform, binding targets imposed on NTPC and the SEBs could be attractive, providing the targets are set at a level which reflects the economic potential for ash utilisation in different areas of India. The result of well designed, geographically differentiated utilisation targets would be to reduce the costs of electricity generation and to benefit ash utilising industries. If such a system were implemented then it would be sensible to allow trading of obligations. A power station that is obliged to utilise a specified volume of ash may find it advantageous to pay another station to take the obligation if that station is better equipped to respond.

Obligations to utilise ash could fit comfortably into the general process of decentralisation of decision making in India and the present requirement on State Governments to prepare Prospective Action Plans for using 50% of fly ash by the year 2000. State governments could fix the initial allocation of obligations in the context of the Action Plans and then allow adjustments among the participants through some trading.

The initial allocation of obligations would be contentious. Objective criteria relating to existing facilities for collection and disposal and proximity to prospective markets should be the basis of allocation. New power stations might be given demanding obligations to reflect the opportunities open to them to start with better adapted technical facilities. This regime of tradable obligations would also have the benefit that it would oblige power stations to take an economic view on the costs and benefits of coal beneficiation and create a framework in which the decision can be analysed.

The advantages of market based instruments in controlling environmental impacts have been discussed earlier and *Section 2.12* gives an account of their applicability in India. It may well be that ash management is a suitable initial application as the attribute is easily measurable and monitored and the number of participants is small. However, local characteristics will need to be considered and care taken to avoid local adverse impacts and disposal problems.

Ash Disposal Tax

The fourth policy option is that of a tax on ash disposal. Such a tax will have a limited effect unless it is combined with power sector reform and the introduction of commercial incentives. But with power sector reform combined with stricter enforcement of environmental standards there is little justification for such a tax.

2.9 *WHAT WOULD IT COST TO IMPLEMENT THE NEW WORLD BANK ENVIRONMENTAL STANDARDS?*

This scenario explores the consequences of adopting the proposed new World Bank standards for air quality and emissions. It poses two subsidiary questions:

- how would the standards affect power plant costs and performance?
- what difference would that make to the choice of fuel and investments?
- what are the consequences for the environment?

2.9.1 *The Alternative Standards Scenario*

The World Bank has proposed as a part of its Pollution Prevention and Abatement Handbook some draft environmental guidelines for new thermal plant. The guidelines are based on the concept of air-sheds and they distinguish air-sheds of good, moderate and poor quality. The guidelines state maximum plant emission levels which should be followed in achieving the site specific emission guidelines. The guidelines also distinguish between power plants greater or less than 500 MW.

Current Indian emission standards for TSP are150mg/m^3 for power generation units of capacity above 200MW and 350 mg/m^3 for units less than 200 MW. The proposed World Bank standards are much lower at 50 mg/m3.
According to the proposed standards, many air-sheds in India would be classified as poor with respect to TSP. The annual average concentrations of TSP permitted by present Indian standards (360µg/m3) substantially exceed the limit in the World Bank alternative (80 µg/m3 for moderate and 160 µg/m3 for poor).

There are no fixed emission standards for SO_2 in India at present. The World Bank has prescribed the emission standard for SO_2 to be 2000 mg/m3. Present Indian ambient quality standards for SO_2 in residential areas (60 µg/m3) correspond roughly to moderate quality air-sheds and industrial areas (80 µg/m3) correspond to poor.

The alternative standards scenario tries to assess the costs of meeting these proposed standards and the effect on fuel choice.

2.9.2 *The Evidence from Andhra Pradesh*

An Air Quality Model has been used to predict the dispersion of pollutants around several potential and actual sites for power stations in Andhra Pradesh. The modelling shows that a power plant of 1000 MW with properly functioning control equipment should not contribute more than 15 µg/m3 of particulates to the annual average of ambient concentration at the site of maximum exposure. With reasonable siting policy it should be possible for clusters of power plants to locate without infringing the proposed limits.

Emissions from industry, from vehicles, mining and unpaved roads can contribute to the background. Consequently, air quality around mine-mouth power plant may be poor even though the contribution from the power plants may not be excessive. This may mean that power plant cannot be put on the site without off-set investments to reduce emissions elsewhere.

Calculations of the SO2 concentrations around a 500 MW power plant burning Indian coal would contribute 9-17 µg/m3 to ambient annual average. With present India standards it may well be possible to site several plant in a region without exceeding the prescribed annual limit of 80 μg/m3. The World Bank alternative standard (50μg/m3) for moderate quality air-sheds would make it more difficult to comply by careful siting and control technologies may be necessary.

Calculations around coastal sites where imported coal would be burnt suggest that the contribution to ambient average concentration from a 500 MW unit could be between 11 - 21 μg/m3. Again, desulphurisation might be necessary if several units were envisaged, but much depends on the sulphur content of the imported coal (based on 1.5% sulphur content).

The consequences on the power system of following the new World Bank standards in Andhra Pradesh were therefore modelled assuming that the particulate control technologies envisaged in IFS would be adequate in most cases to meet the new standards some additional sulphur control measures may be necessary or low sulphur imported fuel used.

After making the least cost expansion plan, it is found that the fuel choice is unaffected by the new standards and desulphurisation is adopted. The affects on cost and sulphur emissions are compared to IFS in *Table 2.80.*

Table 2.80 Environmental Attributes of the Alternative Standards and IFS Scenarios for Andhra Pradesh

Attribute	ALT	IFS
PV of cost (bn Rs)	771	742
PV of SO2 (kt)	2296	2552

Source: Andhra Pradesh Case Study, ASCI Consultancy, 1998.

The average incremental cost of reducing emissions of sulphur dioxide can be calculated from these attributes at about 113 Rs/kg or roughly 3.2$/kg. These costs fall towards the lower end of the range of estimates of damage from SO2 given in *Section 3.4*. There is some indication therefore that the adoption of such standards would be cost-effective.

It should be noted that the calculation represents an upper limit on cost. Other options could well be more cost-effective, for example the purchase of lower sulphur coal, blending of coal or modifying the despatch of plant at critical times. Clean coal technologies such as PFBC and IGCC also reduce sulphur emissions along with other impacts and may also be cost-effective taken as a whole. If there were cheaper means of control then this would reinforce the finding that the new guidelines may be justified.

2.9.3 *The Evidence from Bihar*

The present 24 hour average ambient air quality around power stations in Bihar is shown in *Table 2.81.*

Table 2.81 ***Average Ambient Air Quality near Power Stations***

Site	TSP			SO2			NOx		
	Max.	Min.	Av.	Max.	Min.	Av.	Max.	Min.	Av.
Muzaffarpur	430	82	256	bdl	bdl	bdl	33	10	22
Patratu	589	261	425	18	8	13	13	6	9
Tenughat	397	34	216	36	2	19	36	1	19

Source: Bihar Case Study, SCADA, 1998.

It is clear that the ambient concentrations of SO2 and NOx are well within Indian standards. According to the proposed new World Bank guidelines the air-sheds would be classified as good with respect to SO2. The air-sheds would be classed as moderate or poor with respect to particulates.

Consequently, within the case-study of Bihar no flue gas desulphurisation controls were assumed. All pulverised fuel coal fired plant were assumed to be fitted with conventional ESPs for washed coal or high efficiency ESPs for unwashed coal. The aim was to achieve stack gas concentrations of 50 mg/m3 against the existing 150 mg/m3. The pertinent environmental attributes in the re-optimised plan are shown in *Table 2.82.*

Table 2.82 ***Environmental Attributes of the Alternative Standards and IFS Scenarios for Bihar***

Attribute	ALT	IFS
PV of cost (bn Rs)	198.7	198.1
PV of SO_2 (kt)	908.8	913.5
PV of TSP (kt)	57.2	60.3

Source: Bihar Case Study, SCADA, 1998.

The average incremental unit cost of these controls can be calculated from the Table as 200 Rs/ kg or about \$6 per kg for TSP. The average costs of reducing emissions of sulphur dioxide are 127 Rs/kg or \$3.6 per kg of SO_2. These are similar to those found in

AP and fall towards the lower end of the range of estimates of damage from SO_2 given in *Section 3.4*. From this comparison there is some indication that the adoption of such standards would be cost-effective.

2.10 *WHAT ARE THE ENVIRONMENTAL IMPACTS OF POWER PLANT LOCATION AND CONCENTRATION?*

This section explores the impacts on the environment of plant siting. The work described in earlier sections concludes that construction of many new coal-fired plants is necessary. This section thus analyses how the location and concentration of such coal-fired plant affects the environmental impacts.

Two possibilities for the siting of new Indian-coal-fired power plant are considered:-

1. At a load centre (i.e. in a high population concentration area and generally with many other emitters nearby);
2. At the pit-head (i.e. in a sparsely populated area with few other emitters other than the mine itself).

The effects on the environment of these two options are considered and, where possible, quantified using data and results from the Special and Case Studies. Reference is made to the air quality standards currently operated in India (MoEF norms) and to the proposed World Bank norms for good quality air-sheds (World Bank suggestions to the World Health Organisation). Air quality is the most important issue considered, and the emissions and standards for NOx, SO_2 and TSP are analysed.

Emissions and Air Quality Standards

Current Indian standards and those proposed by the World Bank are shown in *Tables 2.83 and 2.84*. The World Bank standards are significantly more severe; a 'good' quality airshed requires annual average concentrations to be less than 50 $\mu g/m^3$ for SO_2 and 80 $\mu g/m^3$ for SPM. These are respectively 17% and 43% lower than the current Indian standards for Residential/Rural areas and 38% and 78% lower than the current Indian standards for Industrial/Mixed areas. Were the World Bank proposals to be implemented, these reductions could significantly constrain the siting possibilities for new plant.

Table 2.83 Existing Indian MOEF Standards

	Residential/ Rural Areas*			Industrial/ Mixed Areas		
Air Quality Standard, ($\mu g/m^3$)	SO_2	NOx	SPM	SO_2	NOx	SPM
24 hour Average	80 (30)	80 (30)	200 (100)	120	120	500
Annual Average	60 (15)	60 (15)	140 (70)	80	80	360

*Figures in Brackets are for Sensitive Areas

Table 2.84 World Bank proposed air quality standards

	Moderate** Quality	
Air Quality Standard, ($\mu g/m^3$)	SO_2	SPM*
24 hour Average	150	230 (130)
Annual Average	50	80 (50)

*Figures in brackets indicate limits for PM_{10}.
**N.B. Air quality is categorised as 'Poor' under these standards when either the annual mean value is more than twice the standard for an airshed with moderate air quality or when the 95th percentile of the 24 hour mean value of a year exceeds the trigger value for peak exposure levels in an airshed with moderate air quality.

The World Bank standards for emissions have also been expressed in terms of total emissions from power plants during a day, for plant emitting to good quality airsheds. The limits are:-

Plant up to 500 MWe: Maximum Emissions of SO_2=0.2 ton/MWe/day
Part of Plant >500 MWe: Maximum Emissions of SO_2=0.1 ton/MWe/day

Thus a 1000 MWe plant must not exceed SO_2 emissions of 300 ton/day.

Indian guidelines require a stack height of at least 275m for all power plant with capacity of 500 MWe and over. Indian standards on SPM emissions from these power plant stacks are 150 mg/Nm^3 (expressed as a stack gas concentration), whereas the World Bank proposes a two-thirds reduction to just 50 mg/Nm^3. The Andhra Pradesh Pollution Control Board (APPCB) has a separate and lower standard for stack gas concentration of 115 mg/m^3. There are no stack standards for SO_2 and NOx.

Background Concentrations at Load Centre and Pit-Head sites

Ground level concentrations are highly variable and are site specific. In *built-up areas,* there will be other fossil fuel burning and vehicular emissions are the most important factors. A particular problem in many cities is the use of small captive diesel generators and portable petrol generators needed to make up chronic shortages of power. At certain times of day, emissions from these generators can severely affect air quality, particularly with the large emissions of NOx from such plant. Built-up areas also often have large emissions from residential coal burning. When selecting plant location one should also take into account future as well as current pollution sources as they will, in general, increase over time. When selecting plant location one should take into account future as well as current pollution sources as they will, in general, increase over time.

In *rural areas,* the major problem is SPM from dust (principally from soil erosion). This problem is particularly acute during the dry seasons, and is exacerbated by any disturbance to the dust (e.g. road transport on untarred roads).

At *coal mines,* the major emissions are again SPM, both from within the operations of the mine itself and from the disturbance of dust due to transport and other vehicle movements.

Concentrations of SPM, NOx and SO_2 tend to be higher at hill tops rather than on flat terrain. Any given area will of course have its own micro-climate and may naturally disperse pollutants effectively or may allow them to build up at certain periods of the year.

Examples of Background Concentrations

As discussed above, background concentrations are highly variable and site specific. The following are considered to be representative examples gathered from real and modelled data in Andhra Pradesh and Bihar, and from reference sources for other Indian cities. The examples show that standards for SPM are most frequently exceeded at pit-head/rural sites; at residential/industrial sites, SO_2 and NOx are the critical air quality issues.

A sample survey was conducted for three important commercial centres in Bihar (Muzzafarpur, Ranchi and Patna). A major road with a large amount of commercial activity (and, hence, a large number of DG sets) was chosen for each city and the number of DG sets along the roads either directly surveyed or estimated. The emissions from these plants were then estimated and, using computer modelling, estimates made of the concentrations of SO_2 and NOx which would result from the operation of the small DG sets alone. The results of the calculations are shown in *Table 2.85.* These results are highly significant. When compared with current Indian standards, SO_2 emissions of 12.34-28 $\mu g/m^3$ represent 10-23% of the permissible 8-hour average levels in Industrial/Mixed Areas, and 15-35% of those permitted in Residential/Rural Areas. The figures for NOx are more dramatic, representing 58-88% of permissible emissions in Industrial/Mixed Areas, and 88-131% of those permitted in Residential/Rural Areas. The population already complains that these three areas are "full of smoke".

Table 2.85 Air Quality in Commercial Centres due to small Autoproducers

Commercial Centre	SO2 (μg/m³)	NOx (μg/m³)
Muzzafarpur	28	105
Ranchi	24.69	70
Patna	12.34	70

Source: Bihar Case Study, SCADA, 1998.

Background Air Quality at Bihar Power Plant sites

As part of the analysis of emissions from the Bihar power plants, estimates were made, on an annual average basis, of the air quality implications from sources other than the power plants themselves. The results are shown in *Table 2.86.* The flat terrain values are very low, and represent under 3% of the permissible MoEF standards. On hill tops, the figures are very much higher. Indeed the figures for NOx and SO_2 typically represent 70% and 50% of the MoEF limits. The extent of the impacts of these emissions is of course dependent on the population densities at the flat terrain and hill top sites.

Table 2.86 Background Concentrations at Bihar Power Plant sites

Predicted Emissions	SPM (μg/m³)	SO2 (μg/m³)	NOx (μg/m³)
Flat Terrain	0.4-3.23	0.3-1.6	0.5-2.3
Hill Top	66-69	37-40	53-59

Source: Bihar Case Study, SCADA, 1998.

The Talcher Coalfield

The NTPC have plans to extend the existing 2 x 500 MWe generation capacity at Talcher ("Talcher I") In the Bihar Region by a further 4 x 500 MWe of power plant ("Talcher II"). An EIA for this plant was submitted in November 1996, and contained estimates of background air quality(1) . Before that the Asian Development Bank commissioned a study of the Environmental Management for the Talcher region as part of a wider examination of coal-fired power generation.(2)

The air quality was measured at four sampling sites which modelling work had predicted would be the maximum pollutant deposition areas. 24-hour variations in

(1) NTPC, Talcher Super Power Project EIA, November 1996

(2) Ewbank Preece, Environmental Management Assessment Study for the Talcher Region, in National Programme for Environmental Management for Coal-Fired Power Generation, July 1994

pollutant concentrations were measured over a one-year period as shown in *Table 2.87*. The Table shows that the site has a moderate quality airshed throughout the year (1). Average SPM figures are within Indian standards, but exhibit large seasonal variations. The maximum of 332.7 μg/m³ was measured during February, when the winter absences of both rainfall and grass growth, coupled with soil exposure during harvesting and the burning of scrub lands leads to these high levels. Levels in the summer, when temperatures are highest, are slightly lower, possibly due to stray rainfall showers. SO_2 concentrations are well within Indian standards throughout the year, and this reflects the lack of any other major emitters in the area. NOx levels, on average, are low when compared to the standard of 120 μg/m³. Maximum emissions approach 50% of this standard in December.

Table 2.87 Background Air Quality at Talcher (μg/m³)

Location	SPM			SO2			NOx		
	Min	Avge	Max	Min	Avge	Max	Min	Avge	Max
AQ1	14.4	59.2	164.2	bdl	5.0	17.3	bdl	15.5	59.4
AQ2	18.8	114.5	332.7	bdl	5.1	21.7	3.9	14.4	44.7
AQ3	32.7	87.9	114.0	2.3	8.1	19.4	bdl	14.3	48.8
AQ4	11.6	75.1	257.9	bdl	5.5	26.5	bdl	13.0	44.5

*bdl = below detectable limit

Source: NTPC, Talcher II EIA, November 1996

Air Quality at Pit Heads

Emissions of SPM at open cast mines are significant. Emissions of other pollutants are generally negligible, due to the low amount of direct energy use in the mines. There are many operations which contribute to the high SPM burden, including blasting and drilling operations, handling and loading of coal, the dumping of reject and overburden and the gaseous emissions caused by blasting.

In *Bihar* coalfields, SPM typically ranges from 200-600 μg/m³, causing concentrations in nearby residential areas of between 50-200 μg/m³ (i.e. between 25% and 100% of the permissible standards in these areas). A further problem at the mine itself is the production of significant amounts of PM_{10} particles, which are linked to pneumochoneosis. Both water and chemical spraying can be used to reduce the amounts of SPM by damping down the dust on haul roads, excavation areas and loading/unloading points; water spraying is used to some extent and R&D is currently underway to test for suitability of certain chemicals. Such spraying will only reduce SPM to a limited extent.

(1) Air shed quality is deemed moderate if SO2 is below 150mg/m3 and TSP is under 230mg/m3.

The study by TERI on environmental issues in coal mining measured typical concentrations of SPM in three mine areas in West Bengal at 400 $\mu g/m^3$ (i.e. at or close to the permissible limit for industrial sites). (1) Concentrations are seasonally dependent: in the wet summer months (June-September), concentrations are of the order of 5-10 times lower than during the dry periods. However, under prevailing wind conditions, the impact on residential areas is described as 'minimal'. At one of the mines studied in West Bengal, the mean background levels were measured as:-

During Wet season: SPM: 20-60 $\mu g/m^3$ (settlable particles 1-5 g/m^2/month)
During Dry Season: SPM: 200-400 $\mu g/m^3$ (settlable 10-25 g/m^2/month)

Even without coal mining activities, dust resulting from soil erosion is a major problem in the area and an analysis of dust measurements shows that soil erosion produces the largest source of dust. In the coal mine areas, ground level sources of dust (SPM) are estimated to contribute to one-third of the total concentration. Orders of magnitude of dust levels are shown in *Table 2.88.* It can be seen that the levels of SPM only exceed the MOEF standards of 500 $\mu g/m^3$ in the coal mining areas.

Table 2.88 Air Quality at Bihar Pit-Heads

Zones	**SPM ($\mu g/m^3$)**	**Total Dust ($\mu g/m^3$)**	**Settlable Particles (g/m^2/month)**
Vicinity of Coal Mines	200-700	500-1200	20-150
Industrial area with road traffic	100-300	300-1100	5-30

Source: Bihar Case Study, SCADA, 1998.

From the West Bengal study, both road traffic and domestic coal burning are significant contributors to NOx air concentrations. Road traffic tends to result in brief pollution episodes with high levels of NO (typically 500 ppb). These emissions are an important contributor to the formation of ground level ozone. When meterological conditions are unfavourable (mainly at night), domestic coal burning leads to concentrations during 8-12 hour periods of NOx of 100-200 $\mu g/m^3$ (above the limits of standards) with significant levels of SO2 (20-50 $\mu g/m^3$) and CO (5-7 $\mu g/m^3$).

(1) Tata Energy Research Institute, Study of Environmental Issues in Coal mining and Associated Costs, November 1993

Air Quality in Indian Cities

A comprehensive study of the environment in India was undertaken for the MoEF by the South Asia Regional Office of the World Bank [1]. Annual average measurements of the three major air pollutants are shown in *Table 2.89.* The annual averages are generally within standard limits; however the figures mask variability due to both season and location. Pollution hot spots are generally concentrated near to traffic and to industry.

Table 2.89 Annual Average Levels of Pollutants in Indian Cities, 1991,($\mu g/m^3$)

City	SO2	NOx	SPM
Bombay	25.4	29.2	245
Calcutta	63.3	40.8	392
Delhi	20.8	34.8	390
Hyderabad	11.0	19.0	152
Madras	14.1	19.8	130
Ahmedabad	26.7	30.6	306
Kanpur	9.5	13.8	448
Nagpur	8.3	15.5	265
Cochin	6.1	14.4	106

A major study analysing air quality and including measurements in Bombay was undertaken under the Urbair programme. [2] The study concluded that SPM was a major air pollution problem in most of Bombay, and is worst near streets and industrial areas. A reading of over 3,000 $\mu g/m^3$ was taken at a traffic junction in Mahim. SO_2 and NOx standards were not often exceeded.

2.10.2 *Air Quality Impacts due to Power Plant Emissions*

Data from several sources has been used to estimate typical effects on air quality due to emissions from power plant alone. It should be noted that the majority of existing power plant exceed stack gas concentration limits for SPM, often by large amounts. This is due to several factors, including:-

- mineral content of coals used is higher than designed;
- poor maintenance and operating procedures; and
- flue temperatures are not within the range needed for optimal ESP operation.

These problems would not be acceptable in new plant.

(1) World Bank, India's Environment: Taking Stock of Plans, Programs and Priorities, 1996
(2) The Metropolitan Environmental Improvement Programme of the World Bank, Greater Mumbai Report, October 1996

Existing Plant in Andhra Pradesh

Air sheds around Power Plant in Andhra Pradesh would currently be described as poor with respect to SPM under the WB standards; however, calculations suggest that the contribution from power stations to the observed concentrations should be low if ESPs are working at design efficiency. This would require significant changes to operating procedures; an alternative is to renovate ESP equipment in old plant, and focus on other sectors (especially transport) in making significant reductions in background levels.

Measured SPM stack gas concentrations in power plants in Andhra Pradesh range from 100-506 mg/m^3: indeed APSEB feels that it is impossible to meet Indian standards of 150 mg/m^3 using existing technologies, operating procedures and high ash coals which are unwashed. It has appealed that a new standards of 350 mg/Nm^3 would be more appropriate. Ranges of 24 hour average concentrations around the power plant sites are shown in *Table 2.90.*

Table 2.90 Air Quality at Andra Pradesh Power Plant sites (24 hour averages)

Power Plant	SPM (μg/m^3)	SO2 (μg/m^3)	NOx (μg/m^3)
Vijayawada	91-153	14-28	Traces-9
Kothagudem	201-250	3-8	12-16
Nellore	97-206	9-11	Traces-2
Ramagundam	245-253	28-54	17-26
Vijjeswaram (Gas)	93-240	13	9-10

Source: Andhra Pradesh Case Study, ASCI Consultancy, 1998.

2.10.3 New Plant in Andra Pradesh

Limited siting studies undertaken within the framework of the Andhra Pradesh study suggest that with careful siting indigenous coal-fired power plants with properly functioning ESPs can be installed near load centres in Andra Pradesh without infringing standards. The study indicates that 4000 MWe of new plant could be installed near load centres by 2015, and sites can probably be found which can use power plant without additional sulphur reduction strategies. If sulphur needs to be reduced (e.g. a cluster of plants near to a load centre), then the Andra Pradesh study argues that FGD is more cost effective than PFBC technology.

Estimates of air quality impacts at the site of maximum exposure are:-

- A power plant of 1000 MWe with properly functioning control equipment should not contribute more than 15 μg/m^3 of SO_2 to the annual average of ambient concentration at the site of maximum exposure;

- A 500 MWe plant would contribute 9-17 μg/m^3 to the SO_2 burden, 6-17 μg/m^3 to NOx and 0.9-7 μg/m^3 of SPM;
- At coastal sites where imported coal would be burnt, a 500 MWe unit would add 11-21 μg/m^3 to the SO_2 burden - perhaps desulphurisation would be required in this case.

The extra burden of SPM is insignificant, compared either to limits or to emissions from other sources. This assumes that the ESP is properly designed and then operated under optimal conditions.

For the other pollutants, whether these are significant extra burdens of course depends on the site, but a typical estimate of each 500 MWe plant adding 12 μg/m^3 SO_2 corresponds to 10% of the standard in an industrial/mixed site and 15% in a residential area. NOx figures are similar. World Bank limits of 50 μg/m^3 for moderate quality SO_2 will be difficult to meet in many locations, with or without new power plant.

2.10.4 *Existing plant in Bihar*

Measurements of 24 hour averages at the three existing thermal power plants in Bihar are shown in *Table 2.91*. NOx and SO_2 are within World Bank limits, but SPM generally leads to air quality standards which would often be categorised as 'poor'. One of the major reasons for this is the low efficiency of ESPs, where stack gas concentrations of between 240 and 625 mg/m^3 were measured. To meet the World Bank's 50 mg/Nm^3 limit of TSP in stacks, ESPs would require an efficiency of 99.92% for unwashed coal and 99.7% for washed (ash content 30-35%) coal.

Table 2.91 Average Ambient Air Quality at Bihar Power Plant sites

Site		SPM			SO2			NOx	
	Max.	Min.	Av.	Max.	Min.	Av.	Max.	Min.	Av.
Muzaffarpur	430	82	256	bdl	bdl	bdl	33	10	22
Patratu	589	261	425	18	8	13	13	6	9
Tenughat	397	34	216	36	2	19	36	1	19

Source: Bihar Case Study, SCADA, 1998.

Talcher II

An Environmental Impact Assessment for the proposed extension of the Talcher II plant estimated that average figures for SO_2 due to the new 4 x 500 MWe blocks would cause a rise of a maximum of 48.52 μg/m^3. This is consistent with the view from Andra

Pradesh plant that a 500 MWe plant would typically increase the average SO_2 burden by about 12 $\mu g/m^3$. (1)

2.10.5 *Dispersion of Pollutants*

The air quality figures presented in previous sections are for locations close to Power Plants and aim to show the maximum concentrations resulting from the emissions. Ignoring variability due to meterological and topographical factors, the impacts on air quality decrease with distance. The project has included detailed modelling of air quality impacts using detailed computer based Gaussian plume dispersion models.

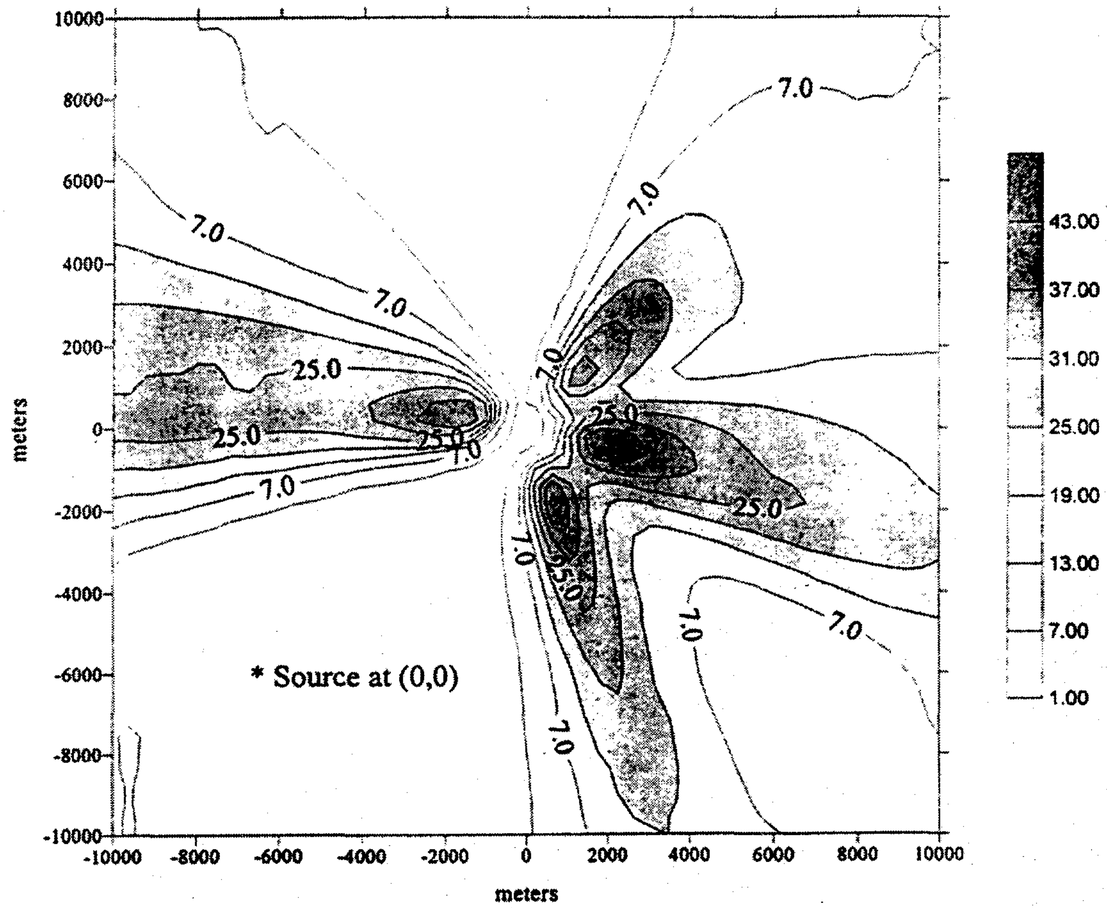
Figure 2.8 show the additional 24 hour average concentrations of SO_2 ($\mu g/m^3$) which would result from a 500 MWe coal-fired plant near Hyderabad. The figures show the resulting concentrations of the pollutants within a 20 x 20 km grid centred on the power plant. The isopleths of constant concentration show that, in general, pollutant concentration reduces rapidly with distance. 'Hot spots' of high concentrations are generally centred near to the power plant itself, modified by inclement meterological conditions (principally wind). Extrapolating from these results, it can be concluded that siting power plant within heavily populated areas will not be acceptable, but that if the plant is carefully sited then it will probably be acceptable to site plant relatively near to load centres. General Indian Guidelines (Ministry of Environment and Forests) on the siting of new thermal power plant recommends a minimum distance of at least 25km from the outer periphery of any Metropolitan Area, National Park or Ecologically Sensitive Area.

2.10.6 *Other differences due to siting*

T&D losses favours load centre siting. Transmissions losses in the high voltage networks are typically under 1% in Western power systems. The losses from T&D in the systems of Bihar and Andra Pradesh are a cause of concern, with estimates of the losses in Bihar ranging from 13% to 32%. This has implications for the choice of site option, but only for Transmission of electricity from a pit head power plant to a load centre; Distribution losses are common to both options. New power plant in India will generally require new transmission lines, and the opportunity is available to limit losses to under 1% by following best international practice. If existing transmission lines in Bihar could be used, then the losses could be as high as 9%. Transmission losses ultimately require the production of more electricity, so it can be assumed that emissions of all pollutants be up to 9% higher than those from a similar power plant sited at a load centre. As a first approximation, it can be assumed that these extra emissions will have a proportional effect on the concentrations of pollutants in the air.

(1) NTPC, Talcher Super Power Project EIA, November 1996

Figure 2.8 SO2 concentrations resulting from a 500 MWe plant at Hyderabad



Source: Andhra Pradesh Case Study, ASCI Consultancy, 1998.

The avoided need for Coal Transportation favours pit-head siting. Although load centre siting benefits over pit head siting by reducing transmission losses, the coal itself must be transported further. In India this is predominantly by rail, with locomotives burning fuel oil. The most important impacts of this transport are:-

- the extra SPM released from the loading and unloading operations (which affect workers rather than the general public);
- CO_2 emissions from the use of the fuel oil.

Energy use (and consequent emissions) from rail transport are very low in comparison to the subsequent burning of the coal in power plant (it is estimated that emissions resulting from a 1000 km rail journey are 25-50 times lower than the consequent combustion of the coal). Coupled with the fact that these emissions are diffuse and irregular and generally in areas of low population, these emissions are not significant.

2.10.7 Conclusions

Proposed World Bank emissions and air quality standards are significantly more stringent than existing MoEF limits. In many built-up areas it would be difficult to meet the World Bank standards, with or without any new power plant. Background emissions of SO_2 and NOx can be significant at load centre sites.

At pit-heads, only background levels of SPM are important. High efficiency ESPs are needed for the reduction of SPM to acceptable limits. The efficiency of the ESP must be at least 99.7% if using washed Indian coal and at least 99.9% if using unwashed Indian coal.

A typical 500 MWe plant using Indian coal will be responsible for additional maximum annual air concentrations of 12 $\mu g/m^3$ SO_2, 12 $\mu g/m^3$ NOx and 4 $\mu g/m^3$ SPM. SPM levels are low when compared either to existing emissions or to standards. A 500 MWe plant would be responsible for 10% of the existing MOEF standard for SO_2 and NOx or 25% of the proposed World Bank standards.

EIAs are required for thermal power plant developments. Unacceptable environmental problems should be avoided for all new plant providing:

- all procedures in the EIA are properly followed, particularly with regard to the disposal of ash
- emissions and air quality standards are enforced;
- design uses high efficiency ESPs, maintains them well and operates the plant within the design criteria required for optimal ESP performance;
- the siting considerations in the Ministry of Environment and Forests' guidelines are followed.

Transmission losses are avoided if load centre sites are chosen. These losses range from under 1% using best available technology up to 9% in present Indian systems. Load centre siting will require rail transportation of coal from the pit head, but emissions resulting from a 1000 km rail journey are estimated to be 25-50 times lower than the subsequent combustion of this coal. Thus neither Transmission losses or Coal Transportation cause significant environmental impacts when compared to coal combustion. Pit-head siting, even for clusters of plant, will be environmentally acceptable providing ESPs are well designed and operated and other dust emissions are minimised.

Siting near load centres is more problematic. Concentrations of SO_2, SPM and NOx are already above permitted levels in some urban areas. New power plant could contribute significantly to these burdens. SPM should not contribute significantly to background concentrations if ESPs are well designed and operated.

Furthermore, impacts from air pollution will be proportional to the size of the recipient population. If population densities are greater at load centres than pit-heads, the damages inflicted by a plant sited at a load centre will be proportionally greater, whether or not ambient standards are met.

2.11 *WHAT ARE THE COSTS OF REDUCING EMISSIONS OF CARBON DIOXIDE?*

Some gases can by their presence in the atmosphere affect the energy balance of the earth and thereby its climate. The principal cause of climate change through this mechanism is carbon dioxide, not because it is an especially powerful agent of radiative forcing, but because it is produced by human activity in vast quantities.

This scenario explores the consequences for the environment of taxing CO_2 emissions. It poses three subsidiary questions:

- what reductions in carbon dioxide emissions can be achieved?
- what technologies are most cost-effective?
- what is the cost of reduction?

2.11.1 *How to do it.*

Emissions of carbon dioxide can be reduced if demand is reduced or if electricity can be produced by generating processes that use less carbon. The demand side options have been investigated in the T&D and DSM scenarios. The contribution of renewable energies to reducing CO_2 has been explored in the renewable scenarios. This section brings together the results of those studies to see what can be done by simultaneously combining all those options.

Carbon emissions can also be reduced by burning fuels with a lower content of carbon. Burning natural gas in a Combined Cycle gas turbine (CCGT) emits much less carbon dioxide per kWh generated than does burning coal in a pulverised fuel plant. The thermal efficiency by which heat is converted to electricity is much higher in the CCGT, say 55% rather than 35%, and less carbon dioxide is produced per unit of heat in burning gas rather than coal because of the high energy carbon-hydrogen bonds in the methane molecule.

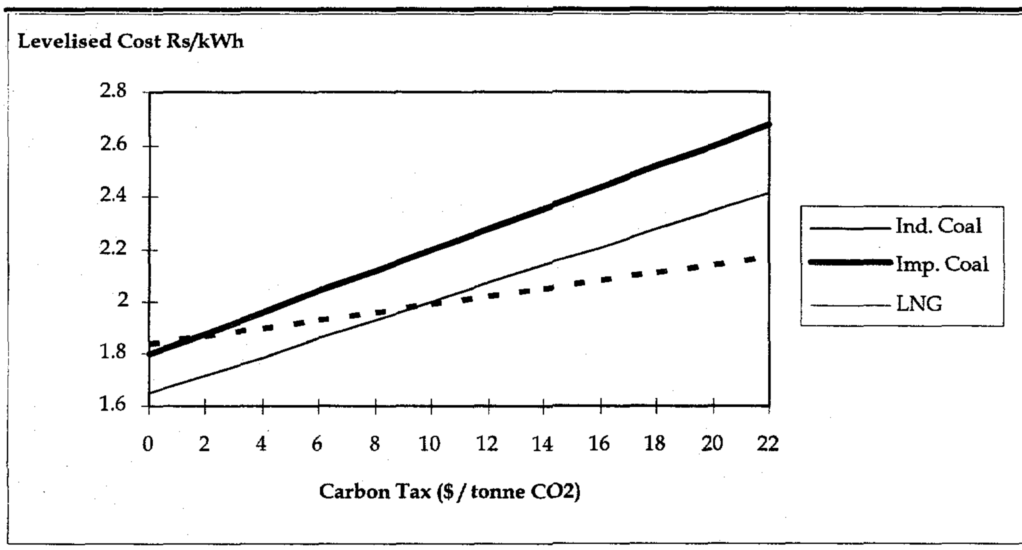
The EIPS project has investigated the supply-side opportunities for reducing carbon dioxide emissions through a series of "carbon tax" scenarios. Three scenarios have been investigated with low, medium and high carbon taxes. In each case a notional tax is applied to the carbon content of all hydrocarbon fuels, but the cost of this tax is not assumed to be passed through to the consumer and therefore does not affect consumer demand.

2.11.2 *The Evidence from Andhra Pradesh*

The DSM, T&D and renewables scenarios all investigate technologies that are both cost-effective and reduce environmental attributes. The most cost-effective mechanism for reducing CO_2 is through rehabilitation of the transmission and distribution system; this is a "win-win" scenario. DSM is also "win-win" although the implementation of this is perhaps more problematic. Together these two activities could save about 144 million tonnes of CO_2 over the period, about 12% of the total production. Renewable energies can only make a small contribution to the reduction of carbon dioxide and that at fairly high cost.

The possibility of bringing forward the substitution of natural gas has been investigated by examining the levelised cost of electricity under various levels of carbon tax. The results are shown in *Figure 2.9*. The underlying fuel cost data relate to the present.

Figure 2.9 Levelised Costs of Electricity at Various Levels of Carbon Tax



Source: Andhra Pradesh Case Study, ASCI Consultancy, 1998.

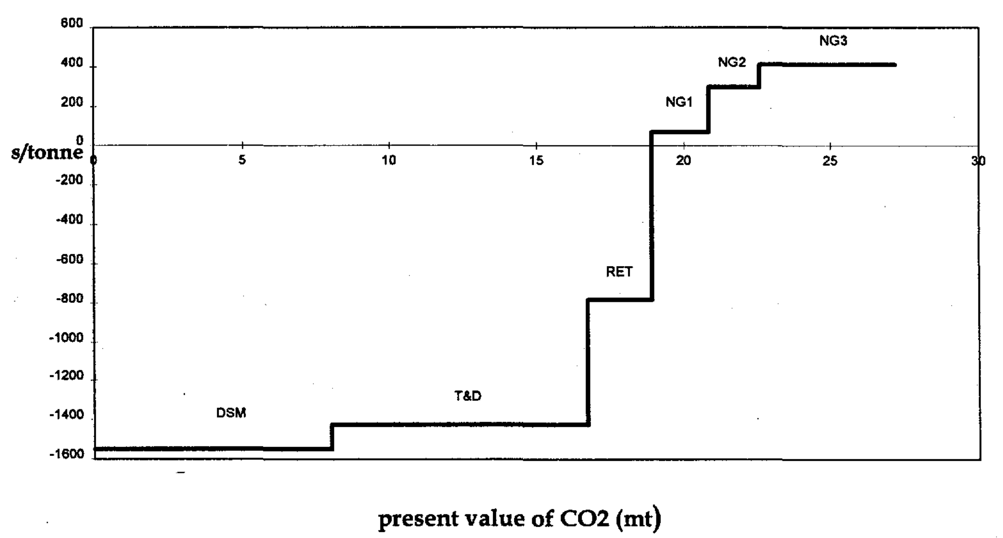
The Figure shows that to bring forward the substitution of LNG to the present will require a subsidy. About $10/ tonne CO_2 saving would be required (1) The technology therefore falls into the scope of the Global Environmental Facility: it is environmentally beneficial, but not in the least cost plan.

2.11.3 *The Evidence from Bihar*

Figure 2.10 summarises the evidence from Bihar. The evidence from the DSM, T&D and renewables scenarios is combined with a set of scenarios that examine the consequences on the supply side of a series of increasing carbon taxes. Tax levels are taken as 175, 350 and 525 Rs/tonne. They have the effect of bringing forward the substitution of natural gas.

The Figure shows the cost of an incremental reduction in carbon dioxide emissions as a function of the cumulative reduction in the present value of carbon dioxide emissions. The cost of reduction of emissions of carbon dioxide by means of a given action is assessed by taking the difference in the present value of the costs of scenarios with and without the relevant action and dividing that value by the difference in the present value of the emissions. NG1, NG2 and NG3 refer to the additional consumption of natural gas under the three scenarios.

Figure 2.10 Cost-reduction curve for CO2 in Bihar



Source: Drawn from the results of the Bihar Case Study, SCADA, 1998.

(1) This is estimated at the present value cost divided by the present value CO2 abated. It should be noted that GEF takes present value cost divided by total CO2.

The cost-curve is approximate for several reasons. The calculations assume that the savings are additive, e.g. if DSM, T&D and natural gas substitution are superimposed then the benefits are assumed to be the summation of the benefits from the individual actions. This assumption overestimates the savings. The curve also neglects the opportunities of higher cost applications of the best options. For example the curve only shows the initial savings in T&D that would be especially cost-effective. More savings could certainly be achieved from rehabilitation of T&D at higher costs but the unit costs of the carbon dioxide savings would still be less than those of substitution of natural gas. For this reason the curve underestimates the savings that are achievable. Despite these deficiencies the curve is a useful indication of the possibilities and their potential and cost.

DSM rehabilitation is the most cost-effective action; T&D comes second. Both are clearly "win-win". Renewable energies are more cost-effective than in Andhra Pradesh.

The savings available from "win-win" actions are about 40 million tonnes or 10% of the present value in the IFS scenario. Those from the complete set of actions are about 85 million tonnes or 21% of the total. These numbers are not immediately obvious from the *Figure 2.10* because the axis there shows the present value of savings. It is interesting to note that the average incremental costs of carbon dioxide savings from the three carbon tax scenarios are 71, 272 and 361 Rs/tonne (1.97, 7.56 and 10.02 US$/tonne respectively). In each case the average incremental cost lies between the value of the carbon tax in the scenario and that in its predecessor. This is to be expected from theory.

The unit cost of saving emissions from using clean coal technology has been calculated as 700 Rs / tonne of CO_2 saved in Andhra Pradesh and 670 Rs / tonne in Bihar.

Table 2.92 summarises the other environmental attributes for the medium carbon tax scenario and compares them to IFS.

Table 2.92 Environmental Attributes of the Medium C-Tax and IFS Scenarios for Bihar

Attribute	Medium Tax	IFS
PV of cost (bn Rs)	198.8	198.1
PV of SO_2 (kt)	883	913
PV of NO_x (kt)	718	732
PV of TSP (kt)	58.2	60.3
PV of CO_2 (mt)	137	141
PV of Ash (mt)	35.5	36.7

Source: Bihar Case Study, SCADA, 1998.

The conclusion can be drawn that there are significant local environmental benefits from policies undertaken to control global impacts.

2.11.4 *The Evidence from other Studies.*

There have been many studies at a micro-level of CO2 reduction in India and in other developing countries. The three studies cited below are only intended as a typical sample.

Mongia et al.(1) analysed 129 different activities in industry. The work includes a 'Business as Usual' scenario which is compared to 'Efficiency', Low Carbon Renewables' and 'Fuel Switch' scenarios. From this comparison, costs of saving carbon are derived. T&D losses are assumed to continue at the present rate (22%). The study concludes that industrial carbon saving can be achieved at negative cost: in 2005, there is the potential to reduce carbon emissions from Industry from 427 to 368 MtC (a reduction of 14%) by energy efficiency measures which would have an average cost of Rs -6.63 /kgC saved. Fuel switching in industry could then offer further savings of 52 MtC (a further 12%) at a cost of Rs -0.77/kgC saved.

Many studies have been made considering the problem of reducing CO_2 emissions in Thailand, where high and concerted economic growth rates are projected in the future. Similarly strong growth rates over relatively long periods are expected in India. The Asian Institute of Technology has constructed cost reduction curves for CO_2 for the year 2030. (2) Over the period 1990-2030, GDP is expected to increase by 6 times and CO_2 emissions by 8-9 times. A 'Business as Usual' scenario is constructed along with two scenarios for CO_2 abatement, termed 'Moderate' and 'Stringent'. Comparisons between the scenarios allows the costs of CO2 emissions abatement to be derived. The study concluded that 10% of projected emissions of CO2 could be abated at or below zero cost.

Sujata Gupta and Neha Khanna investigated strategies for reducing CO2 emissions over a wider scope. (3) They estimated that some 9 billion tonnes of carbon dioxide could be saved in India over thirty five years by actions with investment costs less than $50 per tonne of carbon saved ($13.5 per tonne of CO2). The largest contribution by far to this was from afforestation (about 5.5 billion tonnes), an action that is not considered in the EIPS study. The remaining 3.5 billion tonnes over the thirty five year period is from technical options in the energy sector. It is not possible to make any detailed

(1) Mongia, N., Sathaye. and Mongia p., Energy Use and Carbon Implications in India, Energy Policy, 1992.
(2) Dang, G van, Key Challenges Facing Thailand in the Context of Global CO2 Emission Abatement, Asian Institute of Technology, Bangkok.
(3) Gupta, S. and Khanna, N., India Country Paper, Greenhouse Gas Abatement Costing Study, UNEP

comparison with the EIPS study because the scope, period and manner of presentation of results are all different.

2.12 CAN MARKET BASED INSTRUMENTS CONTRIBUTE TO BETTER ENVIRONMENTAL MANAGEMENT?

2.12.1 *What are MBIs?*

MBIs comprise a wide range of instruments from traditional ones such as pollution taxes and tradeable permits to input taxes, product charges and differential tax rates. *The common element among all MBIs is that they work through the market and alter the behaviour of economic agents (such as firms and households) by changing the incentives/disincentives these agents face.*

2.12.2 *Why use MBIs?*

A number of studies have demonstrated the cost-effectiveness of MBIs over traditional regulatory approaches which require that all polluters meet the same discharge standard (these traditional approaches are termed *'Command and Control'*, CAC). The main factor driving this result is that the costs of reducing pollution are not the same across all firms. Thus the same collective pollution reduction across all firms as under CAC regulations can be achieved at a lower overall cost if those firms with lower than average pollution reduction costs are responsible for higher levels of pollution reduction. A range of empirical studies in the US have been conducted to simulate the potential for cost savings by using MBIs rather than CAC. Typically the simulations show that MBIs could be between 1.5 and 4 times as cheap as the existing CAC regime, across a range of pollutants and locations. Realising these potential savings will require careful MBI design and implementation. Thus MBIs offer the potential to lower overall pollution reduction costs; their practical implementation is much more problematic.

2.12.3 *The Implementation of MBIs*

As part of the World Bank funded Industrial Pollution Prevention Project, MoEF in 1995 appointed a task force "for carrying out a study to evaluate MBIs for industrial pollution abatement". The task force endorsed MBIs for pollution abatement and recommended that current pollution control laws be amended and/or new legislation enacted to allow for MBIs. It also made wide ranging recommendations on changes in the current regime including abolition of the water cess (as it exists now) and fiscal subsidies such as tax concessions on installation of pollutant abatement equipment. The task force did not recommend specific details of MBIs, such as pollution tax rates or details of the number of permits to be allotted.

This and other studies concluded that there are a number of barriers to MBI implementation in India:

- The biggest barrier is inadequate understanding of MBIs among stakeholders, which results in a number of misconceptions. More generally, the use of economic approaches to address environmental problems is not common;
- There is a vested interest in favour of the status quo. Many firms are more comfortable with a CAC regime where they can lobby and manipulate regulators; the bureaucrat-dominated regulatory agencies are also more comfortable with CAC and are suspicious of markets;
- There is a lack of good governance: the institutional/organisational framework for pollution abatement is ineffective; there is a lack of capability at the local/municipal level to address environmental problems, SPCBs are not autonomous from state governments and state boards are often managed by non-specialists with inadequate understanding of the pollution abatement complexities;
- It may be difficult to supersede the CAC regime currently enshrined in existing Law;
- State-owned enterprises (which dominate the power sector) are less responsive to market forces than private firms since they generally face "soft" budgets. There may be the potential for public enterprises to either suffer losses or mark up prices;
- While the total cost to society for meeting environmental standards can be less under MBIs, under some market-based options the cost to industry itself can be higher. For instance, under a system of tradeable permits (which are not distributed free to firms but have to be purchased), firms pay both for the right to pollute as well as for any abatement that they undertake. Similarly a flat tax on discharges will entail firms paying for both controlled and uncontrolled discharges;
- MBIs entail financial transactions, which could give greater scope for malpractice. A further controversy is the important issue of how the funds raised should be used. Industry argues that the funds raised should be reinvested in pollution control equipment; economists argue that any such earmarking is not economically efficient, and would distort the signals being sent to the market: charges are designed to serve as a signal to polluters to guide decisions on levels of control activities, and rebates on control costs would distort this signal.

2.12.4 MBI Options for the Power Sector

The state and local agencies should decide on which MBIs should be used and how they are implemented, in accordance with the nature of the pollution problem and local circumstances. In general, the MBIs will work best (i.e. are most cost-effective) when polluters have to face hard budget constraints.

Taxes could be used for local pollution problems such as ash disposal, particularly for the Small & Medium Enterprise (SME) sector (which is presently excluded from the pollution control regime). For areas with small, diverse sources of emissions/effluents, pollution taxes should be used in accordance with the polluter-pays principle (it would be difficult to issue permits and keep track of their sale/purchase when myriad sources are involved). It is also important to get the tax rates right - rates that are set too low would not have much of an incentive effect and firms would continue to pay and pollute.

An ash disposal tax is feasible but will have a limited effect unless it is combined with power sector reform and the introduction of commercial incentives. But with power sector reform there is little justification for such a tax. Taxes will be more effective if applied to air and water pollution.

Tradeable permits can be used for larger firms providing there is an adequate number of firms in the market to avoid the problem of thin markets. The permits should be implemented *spatially* for given watersheds/airsheds rather than for different industries; since most pollution problems are spatial in character it would not be very useful to apply permits to different industrial sectors without regard to ambient air/water quality. Initially permits can be introduced on a pilot basis, for example looking at emissions of particulate matter only in specific regions of India. Concerning their design, they must lapse over a suitable time period such as 1-2 years, when firms would then have to buy/receive new permits. This system is necessary to remove bias between existing and new entrants to the market. The progressive removal of the number of periods in existence with time allows the authorities to progressively reduce pollution.

Introducing obligations to utilise ash could create a market for trading ash disposal permits. State governments could fix the initial allocation of obligations and then allow adjustments among the participants through some trading. A regime of tradable obligations would have the benefit that it would oblige power stations to take an economic view on the costs and benefits of coal beneficiation and create a framework in which the decision can be analysed. It may well be that ash management is suitable for the application of tradeable permits as the attribute is easily measurable and monitored and the number of participants is small.

3 *MAKING CHOICES*

3.1 *MULTIPLE ATTRIBUTES*

In any decision there are usually implications of different sorts. If these implications can be measured in terms of a single numeraire then all possibilities can be ranked by this numeraire and the best solution is the one at the top of the ranking. This is rarely, if ever, the case with decisions of economic and social consequence. These decisions are associated with multiple and incommensurate attributes and the decision maker must find some way of balancing them.

The attributes can be weighted to bring the problem back to a single numeraire. The weighting may be attributed by some Delphic process for determining priorities or they may purport to represent economic costs. Alternatively some insight can be obtained by plotting two attributes as a scatter diagram. This is one of several techniques of Multiple Attribute Trade-Off Analysis (MATA).

The following three sections:

- summarise the attributes of each scenario;
- demonstrate some simple MATA ; and
- present some estimates of damage costs and discuss their relevance to decision making.

3.2 *THE ATTRIBUTES*

The attributes are *period attributes* that attempt to represent the environmental impacts of a power system over the period of study. They are either present values of flows of cash or emissions or cumulative totals. Present Values are used to collapse a time-stream of values into manageable figures. Cumulative totals are used for ash and CO2 because the effect of these pollutants is proportional to the stock that accumulates over time.

The attributes for Andhra Pradesh are shown in *Table 3.1* The pv of costs for BAU and Reform are on a different basis to the other scenarios because the demand forecasts and the prices for fuel and capital are different. Comparison should therefore be undertaken with care. The attributes for Bihar are shown in *Table 3.2.*

There is some debate as to whether discounted or undiscounted values of carbon dioxide are the more suitable attribute. Examination of the Tables show that ranking of the scenarios according to the cumulative and present value of carbon dioxide is virtually identical, demonstrating that the choice is not material.

Table 3.1 Matrix of Attributes, Andhra Pradesh

Scenario	PV of Total Cost (10^9 Rs)	PV of Total CO2 (mt)	Total CO2 (mt)	PV of Total Sox (kt)	PV of Total NOx (kt)	PV of Total TSP (kt)	Total Ash (mt)	Total Land (ha)
BAU	811	620	1240	2497	2550	251	254	2032
Reforms	745	564	1138	2363	2390	233	226	1808
IFS	742	617	1235	2552	2576	252	251	2008
T&D	713	594	1189	2469	2502	244	242	1936
RET	762	600	1199	2487	2521	245	240	1920
DSM	692	558	1115	2321	2354	228	223	1784
DSM-RET-T&D	693	527	1053	2215	2251	219	211	1688
New Tech	756	597	1193	2160	2323	245	246	1968
Alt stands	771	618	1235	2296	2576	252	251	2008
Green Tech	708	506	1011	1851	2027	212	207	1656

Source: Andhra Pradesh case Study, ASCI Consultancy, 1998.

Table 3.2 Matrix of Attributes, Bihar

Scenario	PV of Total Cost (10^9 Rs)	PV of Total CO2 (mt)	Total CO2 (mt)	PV of Total SOx (kt)	PV of Total TSP (kt)	PV of Total NOx (kt)	PV of Total Ash (mt)
Reforms	172	127	376	828	54	685	34
IFS	198	141	398	913	60	733	37
T&D	186	132	367	860	56	694	35
RET	196	139	387	895	59	723	36
DSM	196	140	395	910	60	731	37
Low C tax	198	139	385	899	59	728	36
Medium C tax	199	137	376	883	58	718	36
High C tax	204	133	353	838	55	692	34
New Tech	202	135	368	755	50	677	37
Alt stands.	199	141	397	909	57	725	37
Green Tech	183	131	358	847	55	701	34
Rehab	176	133	369	862	57	697	35
DSM (EP)	186	133	363	864	57	703	35

Source: Bihar Case Study, SCADA, 1998.

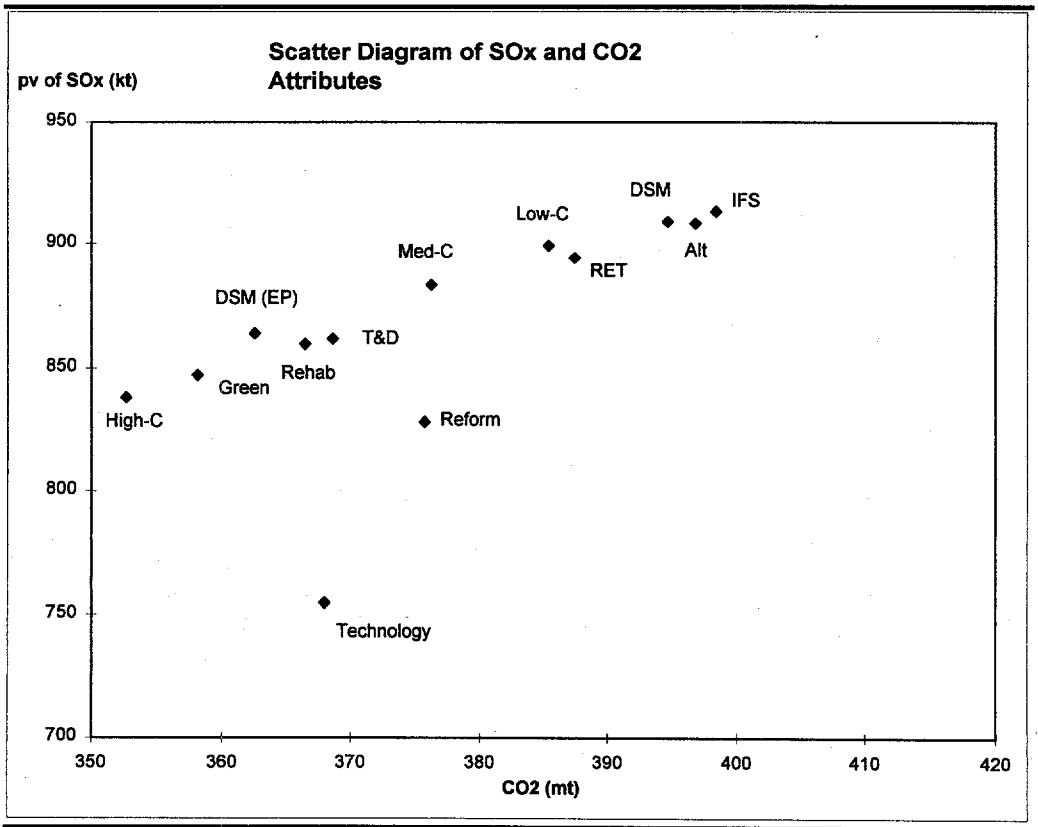
3.3 MULTIPLE ATTRIBUTE TRADE-OFF ANALYSIS

It is hard to draw conclusions from the simple Tables of attributes. A better understanding of the practical consequences and the trade-offs involved in decision making can be obtained by the analysis described below.

3.3.1 *Trade-Off Between Sulphur and Carbon Dioxide Attributes*

Figure 3.1 shows for Bihar an attribute of sulphur (pv of emissions over the period) against an attribute of carbon dioxide emissions (total emissions over the period).

Figure 3.1 Trade-Off Between Sulphur and CO2 Attributes in Bihar



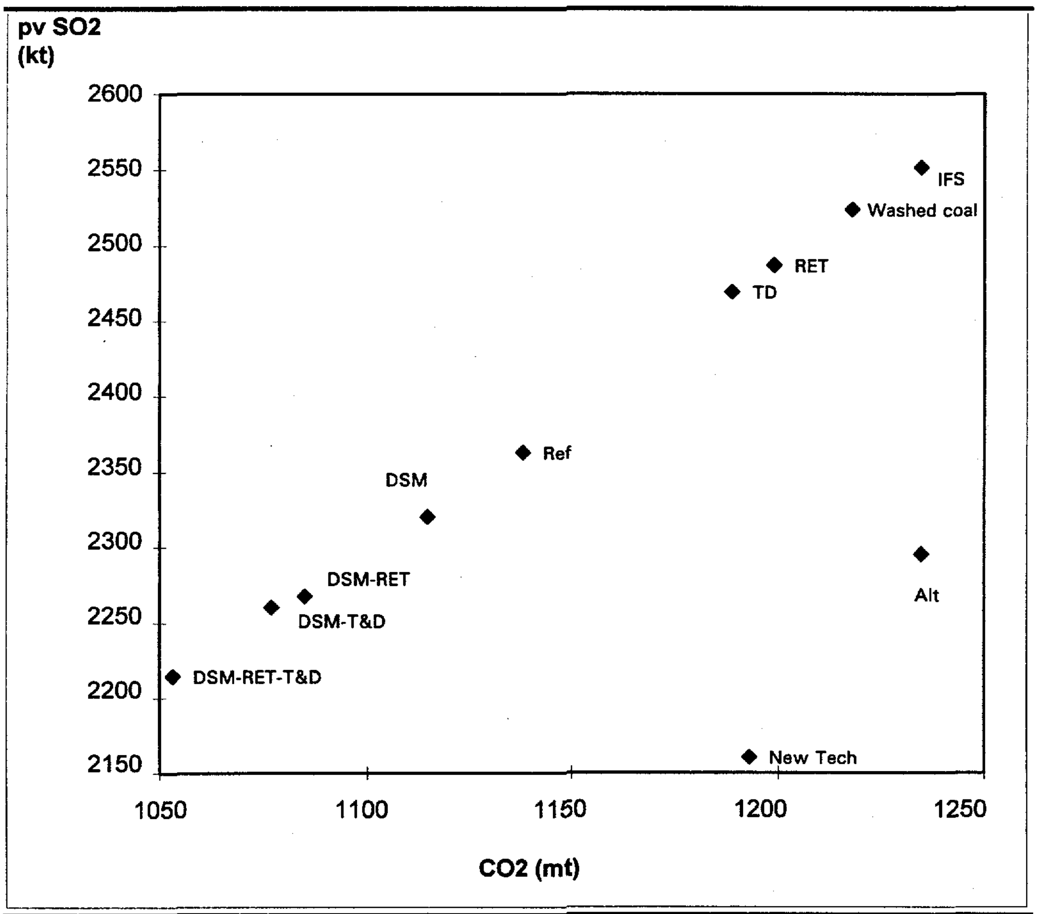
It appears from this diagram, for example, that the Technology scenario is better than the DSM scenario for both attributes. The finding is only of limited significance, because the DSM scenario may be much better on some other attribute, such as cost and anyway they are not mutually exclusive and both policies could be adopted. Subject to these limitations the display of different attributes as scatter diagrams can be helpful.

Probably the most striking aspect of this Figure is that there is little trade-off between SO2 and CO2. The majority of points lie along a straight line. The only outsider is the

Technology scenario that has a disproportionate reduction in sulphur compared to the reduction in carbon dioxide. This is because of the integral control of sulphur within the advanced coal-fired plant in that scenario. The relatively poor performance of the RET and DSM policy options is well brought out in the presentation. The large impacts of the T&D option is evident from the group of scenarios with low sulphur and low carbon dioxide emissions that share the T&D rehabilitation policy. The progressive effect of the carbon tax scenarios in reducing both attributes is also clear. The carbon tax, as represented in this study, affects only the supply side, so its effects can be additive to those of T&D. It is interesting that the Reform case is located among the more successful technical policies.

The same information is given for Andhra Pradesh in *Figure* 3.2.

Figure 3.2 ***Trade-Off Between Sulphur and CO2 Attributes in Andhra Pradesh***



The diagram has several similarities with that for Bihar. The generally high level of correspondence between the sulphur and carbon dioxide attributes is again visible, except for the Technology scenario and to some extent the alternative standards scenario. This latter difference is because in Bihar the sensitive pollutant was considered to be TSP whereas in Andhra Pradesh the sensitive pollutant was considered to be sulphur at coastal power plants burning imported coal, so flue gas desulphurisation equipment was fitted in this scenario, so reducing emissions of SO2, but not CO2.

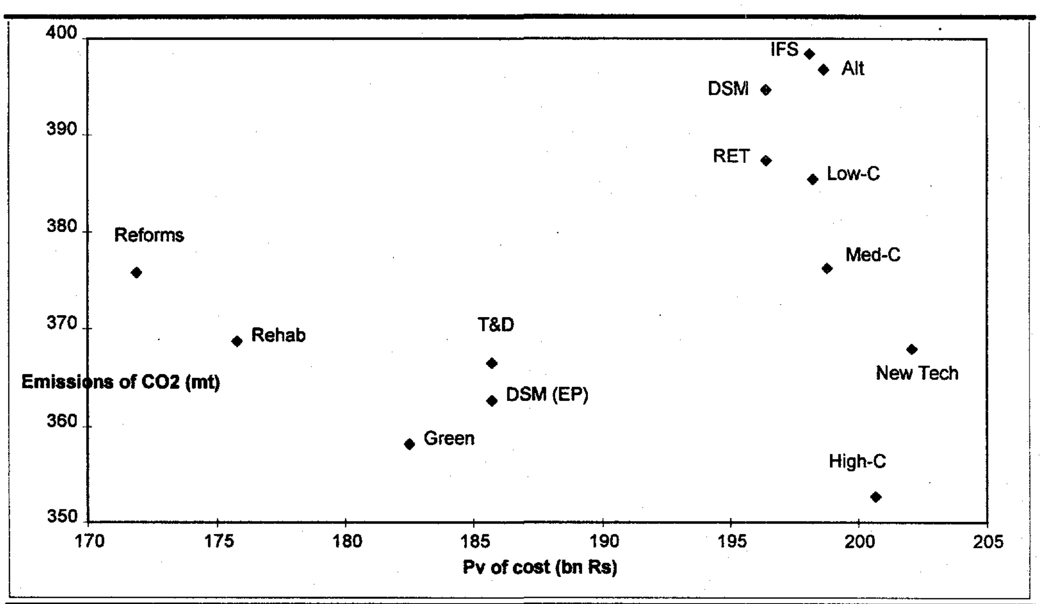
The "best" scenarios are again a group clustered around a particular demand-side policy, in this case DSM. Rehabilitation of T&D is also effective; as is Reform; whilst renewables are not so effective.

The two diagrams bring out clearly the high correlation between local and global environmental attributes. The trade-off curves are only shown for sulphur dioxide, but inspection of *Figures 3.1 and 3.2* shows the same general tendency for other local attributes. Policies undertaken to mitigate global attributes will have large local benefits - there is no conflict between the two interests.

3.3.2 *Trade-Off Between Carbon Dioxide and Cost*

Figure 3.3 illustrates this trade-off for Bihar. It shows an attribute of cost (pv of all costs over the period) against an attribute of carbon dioxide emissions (total emissions over the period).

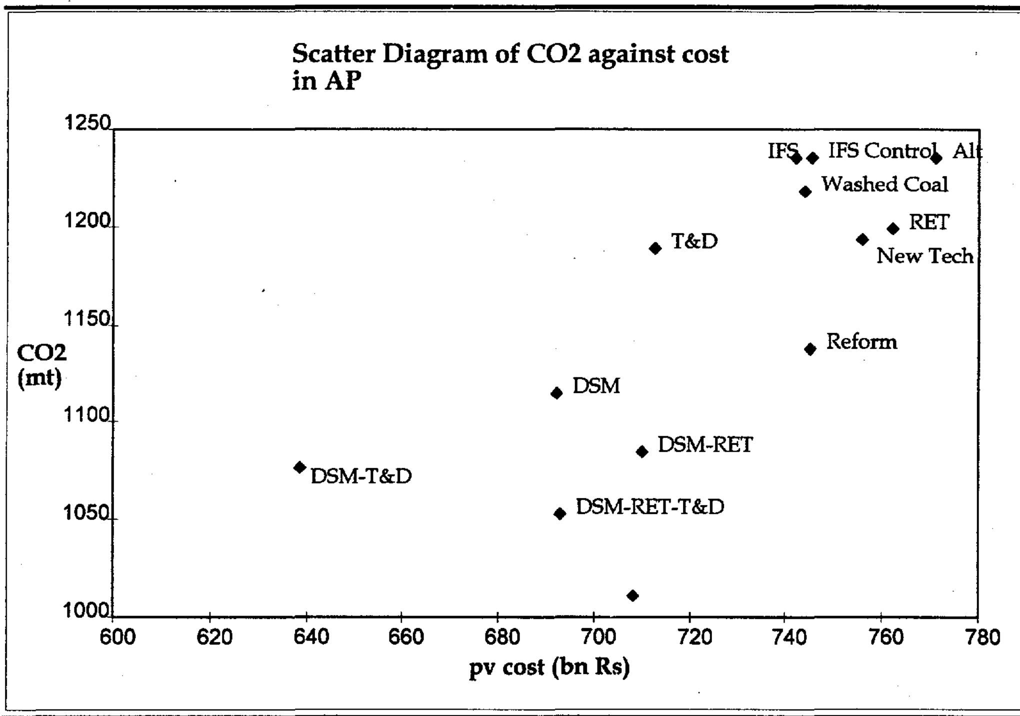
Figure 3.3 Scatter Diagram of Carbon Dioxide against Cost in Bihar



The Figure shows that rehabilitation of T&D is a "win-win" scenario in that both cost and CO2 emissions are reduced. The high carbon tax scenario has a large reduction of carbon dioxide emissions at moderate cost. The scenarios are not mutually exclusive, indeed a large degree of additivity could be expected. BAU cannot be shown on the same plot, because the cost has a different meaning in these cases and is therefore not comparable.

A similar plot for Andhra Pradesh is shown in *Figure 3.4*. The details are significantly different from Bihar, though the grand lines remain the same. The most effective scenarios are those that contain the DSM policy. The major cost savings are from the DSM and T&D options; the interfuel substitution leads to significant carbon savings, but at some cost. The effects of the individual policies can be tracked clearly on the Figure.

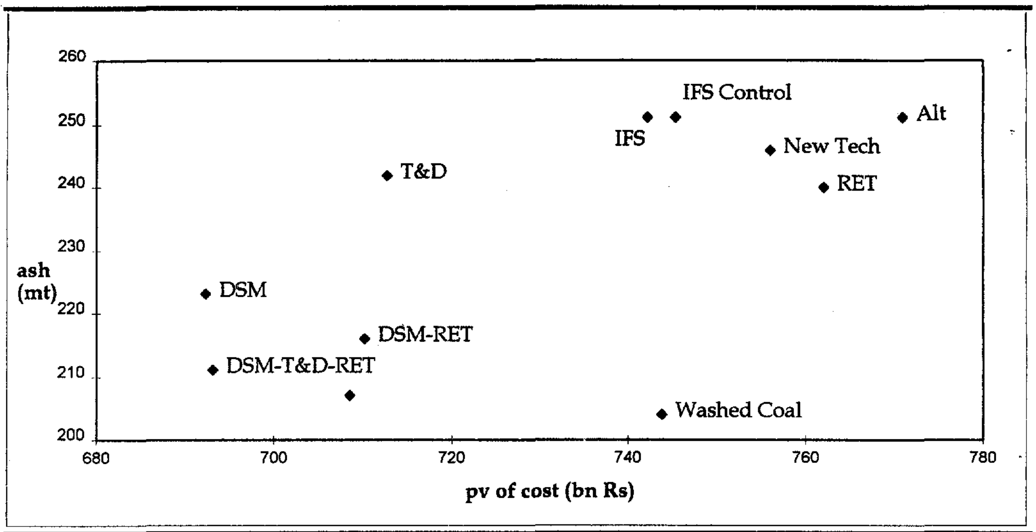
Figure 3.4 Scatter Diagram of Carbon Dioxide against Cost in Andhra Pradesh



3.3.3 *Trade-Off Between Ash and Cost*

Figure 3.5 shows an attribute of cost (pv of all costs over the period) against an attribute of ash production (total ash produced over the period) for the case study of Andhra Pradesh. Care must be taken with this Figure, because in principle all the environmental costs of ash disposal are internalised through compensation for R&R, the cost of acquiring land and the control costs to mitigate impacts. Nevertheless, because ash is such a visible issue in India the trade-off is of some interest.

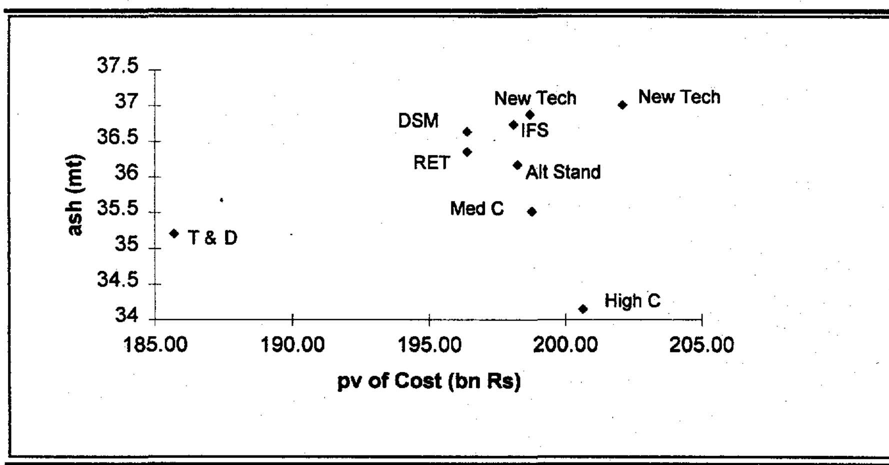
Figure 3.5 ***Scatter Diagram of Ash against Cost in Andhra Pradesh***



The distribution of points is somewhat similar to that of the diagram for carbon dioxide and ash. This is unsurprising in so far as there is a strong correlation between ash production from coal and carbon dioxide production from the same source. Demand side policies therefore have a similar effect in both cases.

Figure 3.6 shows the trade-off in Bihar. The figure shows that rehabilitating transmission and distribution systems is the least cost option. High carbon taxes have the greatest impact on reducing ash. However, the difference in ash generation between all the options is relatively small (upto 10%).

Figure 3.6 ***Scatter Diagram of Ash against Cost in Bihar***



3.3.4 *Trade-Off Between SOx and Cost*

Figure 3.7 shows an attribute of cost (pv of all costs over the period) against an attribute of SOx emission (pv of emissions over the period) for the case study of Andhra Pradesh. The combination of options such as DSM, RET and T&D cumulatively would give lower SO_2 emission levels at a lower cost than the options implemented individually.

Figure 3.7: Scatter Diagram of SOx against cost in Andhra Pradesh:

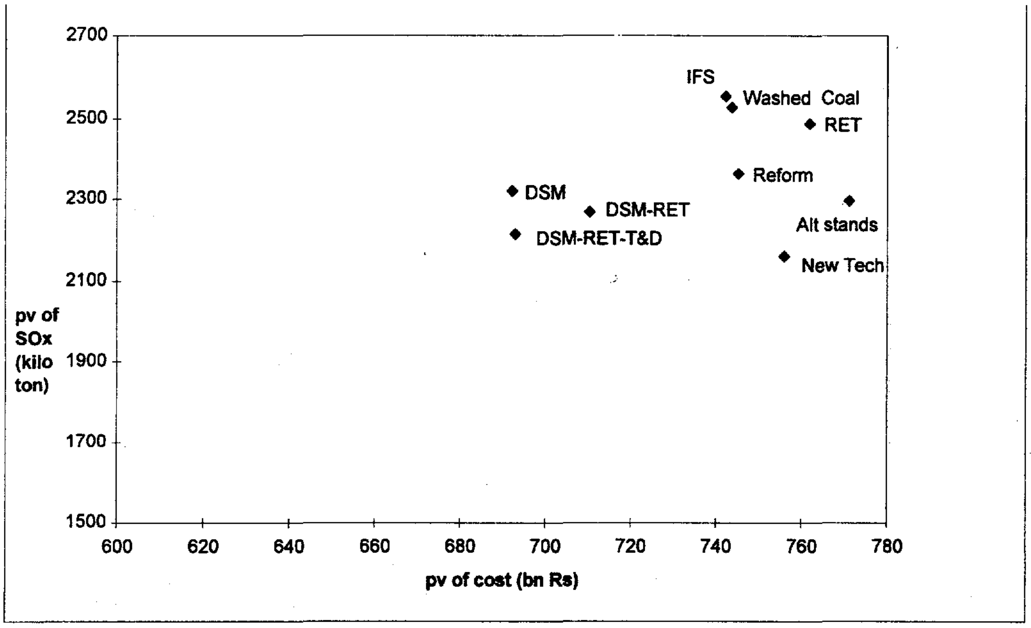


Figure 3.8 illustrates the trade-off in Bihar. It shows options utilising new coal combustion technology cost the same as many other options but that it leads to significantly lower levels of SOx emissions. Reform is also shown to be attractive. Although costs under the Reform scenario are not strictly comparable with other options (because demand levels differ), the Figure suggests that Reform also appears to result in lower SOx emission levels at a moderate cost.

3.3.5 *Trade-Off Between TSP and Cost*

Figure 3.9 shows an attribute of cost (pv of all costs over the period) against an attribute of TSP emission (pv of emissions over the period) for the case study of Andhra Pradesh. The Figure shows that clean coal technologies, though effective at reducing emissions, are also relatively expensive. IFS and Reform scenarios are also shown to be more effective than other options in leading to lower TSP emissions.

Figure 3.8: ***Scatter Diagram of SOx against cost in Bihar:***

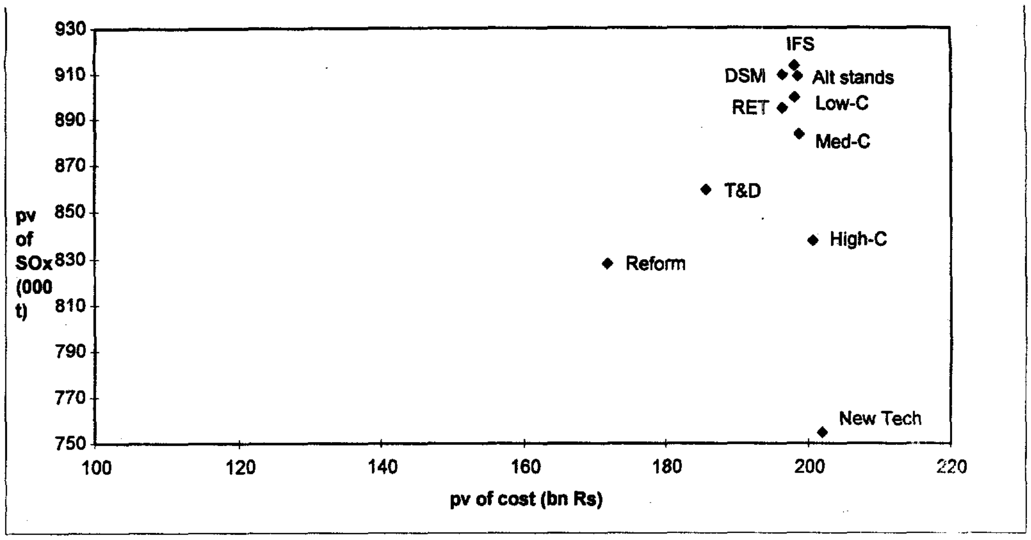


Figure 3.9: ***Scatter Diagram of TSP against cost in Andhra Pradesh:***

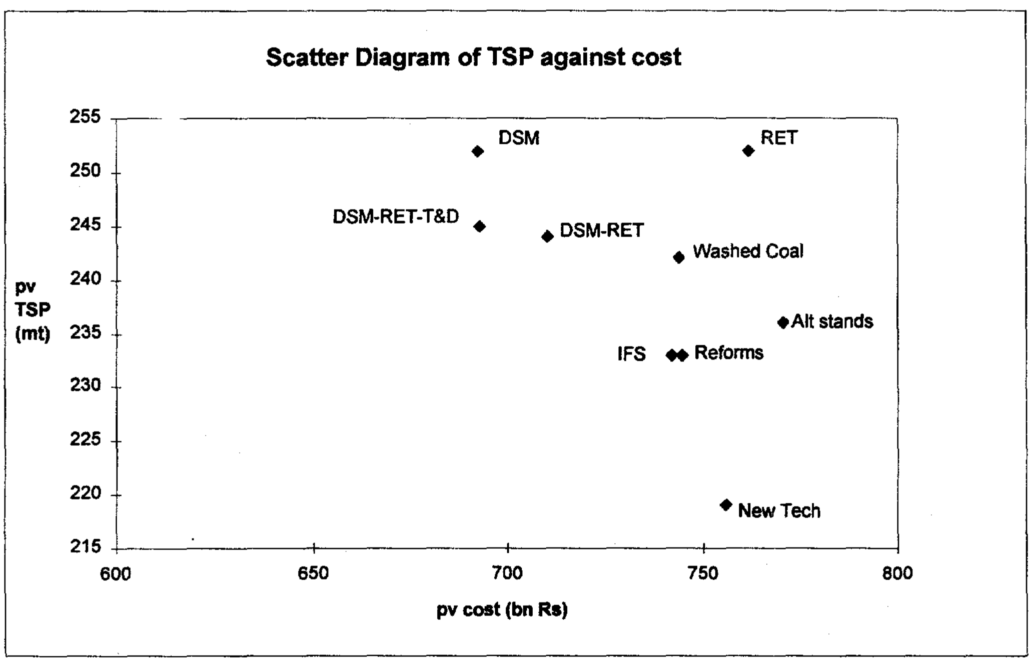
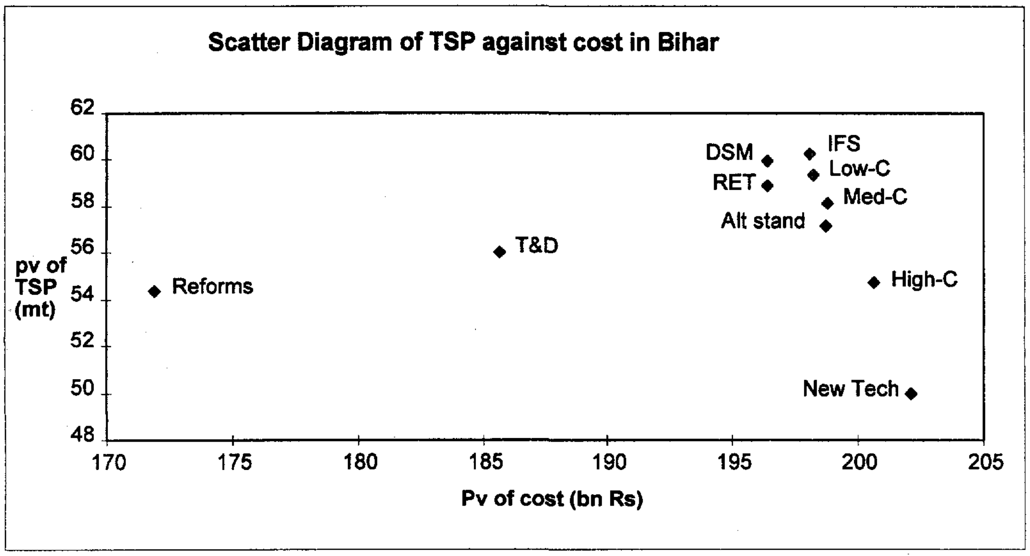


Figure 3.10 shows the trade-off in Bihar. As with AP, new clean coal technologies provide the lowest level of TSP emission but at a high cost. Reform is also shown to be attractive, particularly in cost terms (though not strictly comparable to the other options).

Figure 3.10 Scatter Diagram of TSP against cost in Bihar:



3.4 DAMAGE COSTS

3.4.1 *Introduction*

Environmental impacts can be divided into local, regional and global. Local impacts are those emissions from India which impact on India. These are particularly SO_2, NOx and particulate matter. Regional impacts are those emissions of SO_2 from India which might affect populations outside India or those emissions from neighbouring countries which affect Indian populations. CO_2 emissions are generally considered to be a global problem and the damage costs are thought of in global terms rather than national terms. As trans-boundary pollution is not generally considered a problem in India, the main concern of this Section is with:

- local damage costs, and
- global damage costs.

The literature on global damage costs is applicable to India (although India may be more adversely affected by global warming than some other countries). Many studies have been undertaken to estimate local damage costs in western countries but few are available for developing countries. This Section considers the usefulness of these western estimates for India.

Damage costs are measured in monetary terms but expressed in terms of ambient concentrations of pollutants or per unit of emissions, fuel consumed or electricity generated. In reality, costs depend on ambient concentrations, the level and sensitivity of the population and stock of assets at risk from the pollutant. But the costs are very location and time dependent and are difficult to extrapolate from individual studies to derive aggregate estimates for macro-level policy analysis to be undertaken. The next best measure is the cost per tonne of emissions, followed by fuel consumption and, finally, cost per kWh for different generating technologies. The latter measure is the crudest and cannot be used for specific analysis of state level or even national power sector development plans. Nevertheless, it can be used for broad policy analysis such as, for example, national policy guidelines for the use of different types of power generating technologies.

3.4.2 *Methodologies for Damage Costs from SO_2, NOx and Particulate Matter*

Valuation of Damage Costs

Estimating environmental damage costs of pollutants associated with power involves the following steps:

1. Estimate the emissions levels (eg in tonnes of pollutants).
2. Convert these emissions levels into terms of ambient concentrations of the pollutant in the environment. This usually requires some form of atmospheric modelling.
3. Derive or apply dose response functions for the effects of the ambient concentrations of the pollutants on key receptors (eg human health, trees, etc).
4. Estimate the number of people and stock of environmental assets at risk from exposure to the pollutant.
5. Derive valuations for the impacts (estimated in physical terms in step 3).

There are considerable uncertainties and controversies concerning the currently available knowledge and information on each of the above stages, especially steps 3 and 5.

Dose-Response Functions (DRFs)

Dose-response functions are mostly based on epidemiological data from the US, Canada and the UK and relate ambient air quality to observed changes in morbidity and mortality. There are considerable uncertainties and controversies concerning the currently available DRFs, especially in respect of whether they give a valid association between a pollutant (eg particulates or ozone) and premature deaths. This is because of the difficulties of isolating the effects of the pollutants from the other influences on human health. Moreover, the available studies do not indicate the extent to which the pollutant actually brings forward any deaths, although they adversely affect the health of the population exposed.

The health impacts include, for example:

- respiratory hospital admissions (RHA);
- restricted activity days (RAD) [(1)];
- emergency room visits (ERV);
- minor restricted activity days (MRAD);
- lower respiratory illness in children (LRI); and
- asthma attacks, chronic bronchitis, eye irritation etc.

Valuation of Mortality and Morbidity Impacts

An environmental impact which increases the probability of premature death is costed as the Value of Statistical Life (VSL). This conventional terminology is unfortunately a misleading misnomer which tends to create emotional responses in discussions on the subject. The correct term should be the value of changes in risks of premature death. This can be calculated in a number of different ways including:

- contingent valuation;
- wage-risk studies; and
- avertive behaviour.

The first method simply asks individuals to state their willingness to pay (or accept) using a number of survey techniques. The latter two infer willingness to pay from actual market behaviour.

These techniques can also be used to place a value on morbidity impacts which include:

- medical costs (eg hospital treatment);
- lost output from days off work; and
- welfare losses from pain, discomfort or foregone leisure.

The cost of illness (COI) approach is often used to estimate the first two types of impacts which are more readily quantifiable. However, COI estimates have been criticised for not taking into account the last aspect concerning willingness to pay (WTP) to avoid the welfare losses associated with illnesses; and WTP has been criticised because it fails to account for the direct and indirect costs of illness. The two could potentially be added, but care must be taken to avoid double counting.

(1) For example, days spent in bed and days missed from work.

3.4.3 *Damage Costs for SO2, NOx and Particulate Matter from Western Countries*

Value of a Statistical Life (VSL)

A huge range of statistical life valuations exist. Pearce (1) expressed the findings of 53 studies in £$_{1991}$; the range was £0.5-£14 million. The average values ranged from £1.8-£3.1 million and £1.4-£2.0 million for the UK and US respectively. This large difference is caused by differences in the methodologies applied. Studies funded by the European Commission (2) show that the contingent valuation studies tend to give higher estimates than the wage-risk or avertive behaviour studies.

The VSL has been applied for many years in the transport area to value effects on traffic accident rates. The valuations are for the risks of premature death in a road accident of a healthy adult with about 39 years of remaining life expectancy. The existing estimates for VSL have tended to be transferred directly to value impacts of pollutants on mortality; the validity of this may be questioned, but there are few studies specifically of the value of the effects of pollutants on the risks of premature mortality.

Estimated Values

The earlier valuation studies reported their findings in terms of $ per tonne of pollutant emitted or cents per kWh. Abelson(3) brought together a number of such different studies and compared the average damage costs. These, together with other estimates, are presented in *Table* 3.3

(1) Pearce, D., Bann, C., Georgiou, S., The Social Cost of Fuel Cycles. Report to the UK Department of Trade and Industry by the Centre for Social and Economic Research on the Global Environment (CSERGE), 1992

(2) European Commission, ExternE: Externalities of Energy. Volumes 1-6. EUR 16520-16525 EN, Brussels, 1995

(3) Abelson, P., Project Appraisal and Valuation of the Environment - General Principles and Six Case Studies in Developing Countries. St Martins Press Inc. NY, 1996.

Table 3.3 *Damage Costs[1] of Electricity Generation (UScents[2]/kWh)*

Study	Emission	Gas[3]	Oil	Coal
EPRI (1987) Old Plant	SO2	0.00	0.53	1.05
	NOx	0.03	0.03	0.06
Hohmeyer (1990)	SO2	0.00	0.80	1.60
	NOx	0.38	0.35	0.78
Ottinger et al (1990)	SO2 + NOx	0.37	6.00	4.62
EPRI (1987) New Plant	SO2 + NOx	0.01	0.16	0.34
Pearce (1993) (p/kWh) New Plant	SO2 + NOx	0.03		<0.23
Pearce (1993) (p/kWh) Old Plant	SO2 + NOx			0.56

Notes: 1 Estimates based on abatement costs have been excluded.
2 In 1989 prices.
3 Simple-cycle GT for old plant, CCGT for new.

Table 3.3. shows a wide range of best estimate damage costs. Particularly noticeable is the difference in estimated cost associated with NOx between the EPRI and Hohmeyer studies.(1) The damage costs shown in the Ottinger et al(2) study for oil and coal plants are also well above those for EPRI and Hohmeyer.

Some of the difference between the estimates can be explained by differences in the boundaries considered. Hohmeyer only considers the impact of the operation of the power plant and the generation of electricity whereas Ottinger et al include damage relating to waste management and decommissioning (but are not consistent in scope across all the options considered). Pearce adopts a wider scope including fuel extraction, processing, storage and waste management, but omitting material and energy inputs and construction and decommissioning impacts.

However, the most important reasons for the variation in damage costs are the following differences in the way that the different studies have carried out the steps (2)-(5) outlined in *Section 3.4.2:*

- Differences in the location and manner in which the pollutants are emitted (eg chimney height) and, for example, meteorological and topographical conditions, influence the effect of the emissions on ambient concentration levels of the pollutant; and
- Differences in the level and sensitivity of the people and environmental assets and stock of materials exposed to the pollutant.

(1) Hohmeyer, O., Social Costs of Energy Consumption: External Effects of Electricity Generation in the Federal Republic of Germany . Prepared for European Commission DGXII by the Fraunhofer Institut fuer Systemtechnik und Innovationforschung, Springer, Berl
(2) Ottinger, R. L., Wooley, D. R., Robinson, N. A., Hodas, D. R., Babb, S. E., Environmental Costs of Electricity. PACE University for Environmental Legal Studies. Oceana Publications, 1990

The studies do not provide sufficient detailed information on these factors to enable appropriate interpretation and transfer of their 'results'. We would strongly counsel caution against transferring such estimates to other locations within a country let alone to developing countries.

The more recent studies present their findings more appropriately in terms of the valuation of changes in ambient concentrations of the pollutants (1) or even more appropriately in terms of the valuation of the various specific types of impacts (eg hospital admissions). (2)

3.4.4 *Estimates for SO_2, NOx and Particulate Matter for Developing Countries*

General

There would appear to be few studies attempting to estimate damage costs in developing countries relating to emissions from the power sector. There are some studies which have applied western damage cost figures in developing countries and some which have attempted to estimate damage costs from all pollutants in urban areas.

The results obtained by studies in developed countries are unlikely to be of value to developing countries and are even less likely to be given serious attention by decision makers in those countries.

Dose Response Functions

Commenting on dose-response relationships in air pollution and health, Pearce and Markandya (3) state that *"the sophisticated epidemiological data required for such studies are very rarely available outside the US, and therefore the applicability of this technique in other countries is likely to be rather limited."* However, they argue that the proportional damage to human health, materials, productivity and so on is likely to be approximately similar. Mortality from chronic obstructive pulmonary disease (COPD) and acute respiratory infections (ARIs) appear to be substantially higher in developing countries than in developed countries. According to Pearce (1996) (4) COPD rates in developing countries may be twice as high as equivalent rates in developed counties, and ARIs nearly five times higher.

(1) Maddison, D., Lvovsky, K., Hughes, G., Pearce, D., Air Pollution and the Social Costs of Fuels - A Methodology with Application to Eight Cities. Environment Department Paper. World Bank, 1997
(2) European Commission, ExternE: Externalities of Energy. Volumes 1-6. EUR 16520-16525 EN, Brussels, 1995
(3) Pearce, D. and Markandya, A., Blueprint for a Green Economy. Earthscan, London, 1989
(4) Pearce, D., Econommic Valuation and Health Damage in the Developing World. Energy Policy, Volume 24, Number 7. Elsevier Science Ltd, 1996

Additionally, there are substantial differences in access to health care, differences in demographics and occupational exposure to pollutants, which affect the applicability of DRFs to developing countries. In particular, it is likely that the DRFs from developed countries such as the US will overestimate the effects on hospital admissions and emergency room visits, but they may underestimate other impacts on , for example, possibly mortality and restricted activity days.

In addition, these differences affect the appropriate valuations for the health impacts. The costs in terms of medical treatment incurred will be lower, but the duration and significance of the illnesses may be higher.

Damage Costs

Wages and output are lower in developing countries than in industrialised countries. Hamilton and Atkinson (1) argue that willingness-to-pay is directly related to ability-to-pay, but suggest that this problem can be overcome by using the simple assumption that marginal valuations depend linearly on the difference in income per capita between countries. They also suggest that valuations in other countries will depend on factors such as baseline pollution levels, pollution concentrations, population densities and the underlying health condition and age profile of the general population (2) . However, it is necessary to go further and allow for differences in relative costs between the countries. Thus ERM Economics(3) report that the costs of medical treatment in the UK are roughly one third of the costs of medical treatment used in US based valuation studies. The valuations estimates from the available studies (mainly US based) need to be broken down into their main elements. For example, the morbidity impacts can be broken down in terms of:

1. *Foregone output (from days off work and restricted activity days);*
2. *Medical costs; and*
3. *Suffering and welfare losses from the illness.*

Appropriate measures could then be used to convert each of these elements into more accurate estimates for the developing country in question. Thus the average daily wage can be used for (1); any estimates of medical treatment costs in the country could be

(1) Hamilton, K. and Atkinson, G., Air Pollution and Green Accounts. Energy Policy, Volume 24, Number 7. Elsevier Science Ltd, 1996

(2) It has been argued, for example, that the number of people who succumb to the effects of poor air quality is likely to be proportional to the number of people suffering from some underlying health condition.

(3) ERM Economics, Benefits of lower Ozone Concentrations from Reducing Industries' Emissions of VOCs, London, 1997.

used for (2); and the welfare losses in (3) could be adjusted in the light of income differentials and the other factors determining their incidence and significance.

On-Going Research

The Environment Department of the World Bank (1) is currently carrying out a study which is attempting to develop a methodology to examine the impact of fossil fuel use in major urban conurbations. They applied the methodology to eight cities, predominantly in the developing world: Santiago, Sao Paolo, Bombay, Istanbul, Cracow, Shanghai, Bangkok and Manila. However, the study does not specifically develop dose-response functions or damage costs for these cities. Instead, it uses "meta-analytical" techniques(2) to produce what is termed a "best estimate" of the dose-response relationship based on other studies carried out, presumably in the developed world. The Value of a Statistical Life (VSL), which is used for quantifying health impacts, is also adjusted from values originally calculated by willingness-to-pay studies in developed countries.

The initial conclusions are, nevertheless, interesting, and the results for Bombay are presented in *Tables 3.4 and 3.5.*

Table 3.4 Damage Costs per Tonne of Pollutant by Source for Bombay (US$/tonne)

Pollutant	High Level	Medium Level	Low Level
PM10	855	3,944	29,249
SO_2	127	587	4,349
NOx	95	438	3,243
CO_2	6	6	6

Table 3.5 Damage Costs per Tonne of Fuel in Bombay (US$/tonne)

Fuel	Health Costs	Non-Health Costs	Climate Change Costs	Total Costs
Hard Coal	267	38	15	309
Fuel Oil	37	9	18	64
Diesel	440	127	18	585
Gasoline	115	50	18	183
Wood	186	25	6	217

Source: *Maddison, D., Lvovsky, K. Hughes, G., Pearce, D., Air Pollution and the Social Costs of Fuels - A Methodology with Application in Eight Cities. Environment Department Paper. World Bank, 1997.*

(1) Maddison, D., Lvovsky, K., Hughes, G., Pearce, D., Air Pollution and the Social Costs of Fuels - A Methodology with Application to Eight Cities. Environment Department Paper. World Bank, 1997
(2) Meta-analysis is a generic term for the statistical pooling of results from several studies to obtain aggregate results.

Table 3.5 shows, unsurprisingly, that health impacts dominate the damage categories. It also shows that climate change impacts only amount to a few percent of the total.

3.4.5 *Assessment of Appropriate Damage Costs for India*

Pearce (1) stresses that the figures for damage costs prepared for the UK Government were illustrative only and that much research still needed to be done. He also pointed out that the figures for different types of power plants were "stylised" and that real damage costs are likely to vary on a plant by plant basis. Therefore we need to apply the methodology outlined in *Section 1.1.3* to value the environmental damage costs from a specific plant.

The above literature review has shown that the estimates of environmental damage costs for western countries vary widely. Moreover, while there is an emerging consensus on methodology, there remain considerable uncertainty about some of the empirical relationships in these estimates.

The transfer of damage cost estimates from the west to developing countries adds further to the uncertainty surrounding damage costs. Dose response functions may have value in the developing world but even these are likely to depend, to a certain extent, on local conditions.

Until the uncertainties are removed, external costs will remain contentious and are unlikely to be of any real value to decision makers, especially in the developing world. However, damage cost estimates do have indicative value, and they can at least point decision makers in the right direction. The use of *specific* damage cost figures is likely to be criticised as being an arbitrary exercise.

It is recommended, therefore, that unless an uncontroversial methodology can be developed to accurately transfer and use damage cost estimates from the developed world to the developing world (which seems unlikely), a detailed in situ study is carried out in India, so that the full extent of damage to the environment can be quantified to assist decision makers and help to shape appropriate policies. As such, the damage cost estimates have not been used in this synthesis analysis.

The lack of national damage cost data demonstrates the need for original research on pollution damage costs incurred in India to be carried out. This work should build on the research the World Bank has already to carried out in cities in other developing countries.

(1) Pearce, D., Bann, C., Georgiou, S., The Social Cost of Fuel Cycles. Report to the UK Department of Trade and Industry by the Centre for Social and Economic Research on the Global Environment (CSERGE), 1992

3.4.6 *Damage Costs from Greenhouse Gas Emissions*

The ExternE Report [1] reviews the current techniques for estimating the "cost " of global warming. These mainly include estimation of the adaptation and residual damage costs that would arise in a number of specific subjects (eg agriculture, impacts of sea level rise) under a climate change scenario. The ExternE concludes that with the current state of knowledge, it is difficult to make any reliable estimate of global warming damage.

The Intergovernmental Panel on Climate Change (IPCC)[2] expects the following aggregate damages for a doubling in global CO_2 concentrations:

1. world impact = 1.5 - 2.0% of world GNP;
2. developed country impact = 1.0 - 1.5% of national GNP; and
3. developing country impact = 2.0 - 9.0% of national GNP.

However, even these figures are best guess estimates and do not reflect uncertainties or factors such as the rate of change or the rate of adaptation. The large range of estimates for developing countries indicates the even greater uncertainty in damage values due to less studies being carried out in these countries.

The IPCC review of damage costs reports studies with a range of US$5-125/tonne of carbon[3] (with most estimates at the lower end of this range) (0.1-2.3 cents/kWh) for a typical coal fuel cycle. The IPCC suggested that even this range does not fully represent the range of uncertainty.

Maddison et al review the same studies as the IPPC but exclude the higher estimates; they settle on a range of US$$_{1990}$5-20/tonne of carbon. Nordhaus (1991) [4] estimates the cost of global warming to be US_{1989}$7.3/tonne of carbon based on losses of 1% of global GNP.

(1) European Commission, ExternE: Externalities of Energy. Volumes 1-6. EUR 16520-16525 EN, Brussels, 1995
(2) Intergovernmental Panel on Climate Change, Climate Change 1995: Economic and Social Dimensions of Climate Change. Contribution of Working Group III to the Second Assessment Report. Cambridge University Press, 1996
(3) Source: Intergovernmental Panel on Climate Change (1996).
(4) Nordhaus, W.,To Slow or Not to Slow: The Economics of Global Warming. Economic Journal, Volume 101, July, 1991

Pearce et al [(1)] suggest that a more realistic range of damage estimates is £$_{1991}$5.8-17.3/tonne of carbon in CO_2 equivalents. On the basis of this analysis they derived the following externality adders for climate change:

- existing power plant coal: 0.20 - 0.61 p/kWh
- new power plant coal: 0.17 - 0.51 p/kWh
- oil: 0.17 - 0.52 p/kWh
- gas: 0.08 - 0.24 p/kWh
- nuclear: 0.01 - 0.02 p/kWh

Because global warming impacts are not country specific, the same global warming costs for CO_2 emissions from power stations can be applied to all countries including developing countries. However, when making policy decisions, what matters is India's rights and obligations.

(1) Pearce, D., Bann, C., Georgiou, S., The Social Cost of Fuel Cycles. Report to the UK Department of Trade and Industry by the Centre for Social and Economic Research on the Global Environment (CSERGE), 1992

4 WHERE DO WE GO FROM HERE?

4.1 INTRODUCTION

The purpose of this section is twofold. First, we discuss, in *Section 4.2*, the possibilities and implications for implementing the findings of the analyses presented in *Sections 2 and 3*. Second, in *Section 4.3*, we consider the implementation of the decision making process and tool, which was outlined in *Section 1* (dissemination). This section also draws upon the material presented in the earlier part of this Report and the contributions made at the National Decision Makers' and NGO Workshops, held in Delhi, in early May 1998.

4.2 IMPLEMENTATION OF FINDINGS FROM THE NATIONAL SYNTHESIS

4.2.1 Broad Policy Framework

The Current Situation in the Power Sector

The Synthesis finds that the present organisation and structure of the power systems in AP and Bihar provide a set of managerial and other incentives that are likely to continue to generate low revenues for the utilities; make the SEBs unable to invest in plant modernisation and pollution control measures and continue to use fuels in an uneconomic way, with little regard for present environmental standards; and encourage the inefficient use of energy by consumers. The consequences of maintaining the current situation in AP and Bihar have been described in *Section 2.1* and include: a negative and deteriorating rate of return on assets; high technical and non-technical losses; steeply rising emissions to the environment; land degradation and population displacement; and a mounting ash disposal and utilisation problem.

Extrapolating these conditions to India as a whole suggests that by 2014/15 the power sector in India could be producing roughly three times as much SO2, NOx, particulate emissions and ash compared with present conditions: by that time, the ash disposal facilities around power plants would require over 1,000 km^2 of land or about one square metre per person; and CO2 emissions could be 775 mt per year, compared to 1,000 mt presently produced by power generation in the EU. These data indicate that BAU is not sustainable, financially or environmentally.

Policy Alternatives

The Synthesis shows that there are policy options which can mitigate the environmental impact of power generation. The quantitative analysis of the Synthesis Report and, in large measure, the discussions at the National Decision Makers' and NGO Workshops, point to economic and energy sector reform as a particularly attractive alternative to BAU, even if such reform is defined very conservatively, in terms of tariff increases and improvements in operational efficiency. Notably, reform thus defined would improve the financial position of utilities and create better incentives for cost-effective power system planning: the environmental performance of the energy sector is likely to benefit substantially, as detailed below.

- Moving tariff levels and structures more into line with costs will increase utility revenues, facilitating environmental expenditure and environmental compliance. The Synthesis estimates that the costs of environmental mitigation measures should not be a deterrent to their implementation: they would add approximately 70Rs/tonne of coal mined, or 5-12% of total cost, depending on coal grade; and 7% to the capital cost of a conventional coal-fired power plant, excluding R&R costs (which are site-specific). This cost should be affordable with even limited increases in tariffs from current levels.
- These tariff increases will motivate consumers to conserve energy and improve the end-use efficiency of appliances (e.g. installing higher efficiency pump sets).
- It is difficult to close non-compliant plants at the moment, because of the serious supply constraint. The evidence from AP and Bihar shows that the reserve margin will be higher and LOLP lower under reform. The implications for system reliability of a plant closure would therefore be less significant and enforcement of compliance becomes practical.
- Increased commercialisation combined with stricter environmental compliance will increase motivation to find least cost solutions. These are likely to benefit the environment, e.g. by motivating power plant operators to find ways to utilise fly ash as an alternative to disposal.
- The selection of fuel type based on economic costs, including the internalisation of environmental costs, will improve the competitive position of environmentally more friendly sources, such as natural gas and renewable energy.
- Investments in new modern plants will eventually displace the older, less efficient and more polluting plants.

The AP model clearly indicates the environmental benefits which accrue under a reform package, compared with BAU: the present values of emissions of NOx, SOx and TSP fall by 5-7%; whilst cumulative emissions of CO2 and ash production fall by 8% and 11% respectively by 2015. Meanwhile, the demand for electricity by industry increases by 30% in 2015, indicating strong concurrent economic development.

However, it should be noted that where there is now large suppressed demand, reform may increase environmental impacts, if the effect of higher prices on demand is outweighed by growth in incomes and if increased revenues permit utilities to build more power plants to meet demand. Nevertheless, the effects of reform in the Bihar model are salutary: despite meeting sales which are one-third higher by 2015 under reform compared with BAU (*Table* 2.37) and reducing system LOLP from 40% to 5% by 2001, environmental attributes all fall (NOx, SOx and TSP by 11-15%, cumulative CO2 and ash by 11% and 6% respectively), indicating that the beneficial aspects of reform dominate (*Table* 2.39).

The quantitative analysis in the case studies also explored the implications of choosing between key demand-side and supply-side options on the basis of economic costs, with environmental costs fully internalised. These options (e.g. renewables, DSM and T&D rehabilitation) show important possibilities to reduce India's dependence on coal for power generation; but there was a consensus at the National Decision Makers' and NGO Workshops that, without some measure of reform, the options may not be taken up or, if implemented, may not be sustainable. The reason is that many of the specific measures have common factors influencing their potential effectiveness, including:

- getting the price of electricity right (for DSM), to send correct signals to consumers to invest in efficient economic activities and appliances;
- getting the price of fuels right, "to create a more level playing field" (for natural gas and renewables);
- increasing the commercial motivation of utilities (for T&D rehabilitation and ash management); and
- increasing the funds available to utilities (through raising tariffs).

Therefore, whilst individually many policies lead to environmental improvement, the overriding finding is that they may be most effective if introduced as an integrated package within the framework of sector reform. Indeed, no single element of the reform policy in isolation will provide the solution. For example, in AP, a combination of options (renewables, DSM, T&D rehabilitation, coal washing and clean coal technologies) reduces coal-based power generation by 18% by 2015, compared with IFS. In Bihar, a mix of DSM, renewables and T&D rehabilitation reduces coal-based power generation by 15% over the same period.

Specific Measures for Policy Change and Environmental Improvement

Section 4.2.1 identified a broad policy framework that would mitigate the environmental impacts from the power sector. This section now considers some of the individual components of the framework in more detail, notably: demand side management (DSM), transmission and distribution (T&D) rehabilitation, renewable energy technologies (RETs), coal beneficiation, clean-coal combustion technologies, ash utilisation, market-based instruments (MBIs), and alternative standards. We identify potential mechanisms for the implementation of these measures, how they interrelate and their possible implications for policy makers, utilities, consumers and the environment. The discussion reflects the views, experiences, concerns and priorities of the delegates present at the National Decision Makers' and NGO Workshops.

Demand Side Management

DSM has been shown in both case studies to be beneficial for the environment (through reduced energy requirements) and cost-effective (as lower demand reduces capacity and energy requirements). In Bihar and AP it is estimated that the introduction of DSM measures could reduce environmental impacts by 5-10% whilst leading to a present value of cost saving (net of the DSM expenditures) in the order of 6.5%.

There are various types of DSM program which can be implemented and/or funded by a host of institutions - utilities, state or private sector. The programmes focus on energy conservation and include installation of high efficiency refrigerators and pumps, metering pumpsets, industrial cogeneration and energy saving lighting units. Relevant policies that have been adopted by various countries which could be used in India include:

- promotion of Energy Service Companies (ESCOs) to fund and manage investments in energy efficiency and to share savings with users;
- levies on utilities to fund energy conservation programmes;
- requirements on utilities to engage in DSM as a condition imposed by regulators for construction permits or tariff increases.

Delegates to the National Decision Makers' Workshop suggested that the following measures would also aid the successful adoption of DSM programmes:

- the introduction of performance related financial incentives using techniques such as energy efficiency ratings;
- increasing public awareness of the need for energy saving and practical methods for all types of consumers;
- increased finance for R&D and consequent distribution of appropriate energy efficient technology;
- improved methods for measuring energy savings e.g. through testing facilities, in order to make more transparent results and benefits from DSM measures.

DSM can be implemented as an isolated policy but is likely to be more effective combined with sectoral reform and other initiatives such as T&D rehabilitation.

Delegates at the National Decision Makers' Workshop noted that reform, through raising tariffs, will act as a financial incentive for consumers (mainly agricultural) to adopt more energy efficient economic practices.

Following reform, utilities tend to lose financial interest to participate in DSM activities but there is an increased role for the private sector to assist consumers in changing their behaviour by making appropriate technology available [(1)]. An independent ESCO, for example, could take on the task of promoting DSM programmes as a commercial proposition. There has been significant activity along these lines and some degree of success in the USA and Western Europe.

T&D Rehabilitation

Both the AP and Bihar case studies demonstrate that T&D rehabilitation is likely to be a "win-win" option. T&D losses in these two states are at least 30%; whereas it is expected

(1) The utility will only be a willing participant in engaging in energy saving activities for its customers if its costs decrease more than the loss of revenues. Under reform, tariff covering costs will at least match revenues with generation costs.

that 10% losses are achievable in most states in the long run. This is in line with current performances in Singapore and Korea. In AP, it was estimated that rehabilitation of the transmission and distribution system could lead to a 3% reduction of all environmental attributes compared to the IFS scenario; whilst the present worth of costs would fall simultaneously by 4%. The power system expansion analysis in Bihar shows that these reductions in environmental attributes would be even higher, 5-6%; whilst the present worth of expenditures on power plant and associated operating costs would fall by more than 6%.

There is a need to reduce non-technical losses and technical losses. Capital is required to reduce technical losses whilst commercial motivation will lead to improved maintenance, metering, monitoring, billing and collection, which will reduce technical and non-technical losses. A Reform framework appears to provide both. Higher tariffs will increase utility revenues and improve their cash flow, thereby facilitating plant expenditure on rehabilitation. There have been observations that adequate funds are not the only constraint and that there is also an allocation issue - available capital appears to be invested in new plant rather than rehabilitation. When power supplies are deficient, experience from India and elsewhere suggests that operators focus their attention and limited resources on constructing new generating plant, rather than carrying out T&D rehabilitation. The commercial motivation that accompanies reform should improve the allocation of funds towards the most cost-effective means of increasing system capacity. Therefore the potential for T&D rehabilitation and all its benefits appears much greater under a Reform framework.

The implementation of T&D rehabilitation programmes can be further facilitated by the following measures (which were raised in the National Decision Makers' Workshop):

- access to appropriate technology and tools (such as computers);
- human resource development training;
- increased energy accounting and auditing; and
- examination of the role for private companies to become involved in electricity distribution.

Renewable Energy Technology

There are several types of renewable energy supply. The results of the studies show that small hydro, wind and bagasse cogeneration are the most important technologies and their relative importance depends on the renewable resources in the State under consideration, as aptly demonstrated by the case studies (with Bihar favouring bagasse and AP developing hydro and wind power). However, on the basis of existing knowledge, the overall potential for economic RET generation is limited. There are also problems of timing, reliability and quality of supply.

Each RET has a set of specific technological and economic issues which will affect its implementation:

- solar photovoltaics (SPV) currently contribute less than 0.5% of RET power generation in India. Grid connected SPV is not expected to significantly increase. The cost of photo voltaic cells has fallen rapidly; and, with more widespread adoption of RETs (and hence possible reductions in unit costs from economies of scale in production), the unit costs of production should decline further. But they are expected to remain above the costs from other RETs and fossil fuels. However, solar energy may prove important for rural areas that are far from the grid.
- the scale of implementation of wind power is constrained by operational problems in matching the availability (supply) with the load duration curve (demand). Wind power is often seasonally variable, with peak output from wind turbines occurring during the monsoon season; whilst demand for electricity is generally highest in the dry season. The plant load factor of wind farms in AP, for example, is currently around only 22%, substantially increasing their costs per kWh relative to fossil fuels.
- whilst the potential in India for generating power from crop residues and other sources of biomass is undoubtedly large, there are technical difficulties ranging from the combustion properties of the biomass to the logistical problems of ensuring adequate and timely supplies.

The analysis suggests that the potential for utilising RETs is significant but cannot change the dominant position of fossil fuels in the overall energy mix. In AP, RET power generation potential was estimated to represent only about 6% of capacity by 2015, although a fundamental restructuring of commercial incentives to the power and sugar sectors might increase the presently very low levels of cogeneration from bagasse.

The use of RETs has significant environmental benefits, but (on the basis of known technology) RETs can only be a small part of any strategy for managing the environmental impacts of the power sector in the near- to medium-term. As renewable energy may not be available at the times of system peak it may not reduce the capital investment that is required for the system and therefore may not actually displace thermal plant construction . Therefore RET related policies would need to be implemented in addition to other energy policies.

The special study on RETs argued that subsidies would have to be maintained if the share of renewables is to increase. It found that renewables could contribute to approximately 3-4% of India's power generation capacity by 2010 if combined with government financial incentives but would be only half that if not supported by incentives.

On the other hand, if energy sector reform becomes more widespread, the implicit or hidden subsidies often associated with conventional fuels will be reduced. RETs in general will compete more effectively with fossil fuels if financial and economic costs for all fuels are brought closer together. Especially in the case of solar photovoltaics, where substantial technical progress has recently been made, market penetration will improve in the longer term. This time period can be compressed if the government promotes increased R&D and international information exchange in this field to try and bring down the costs.

Coal Beneficiation

Coal beneficiation has been adopted in many countries but its use in India remains controversial. The main advantages of beneficiation lie in:

- avoiding the costs of transporting large amounts of mineral waste;
- reducing the volume of ash disposal at power plants; and
- improving the availability and reducing the capital and operating costs of power plants.

The first two points are straightforward. For example, based on the Inter-Fuel Substitution Special Study, as reported in *Table 2.22*, the economic cost of transport for coal can be 20-25% of delivered cost (or even higher) for power plants away from pit-head sites. The cost of ash disposal was estimated at $6/tonne in *Section 2.8.3*.

The third point is more complex. *Section 2.7.5* argues that the principal economic benefit of coal washing lies in the lower capital and operating costs of power plants which are designed specifically to burn washed coal. The savings in power plant costs are estimated to be between Rs. 175/tonne and Rs. 350/tonne based on the calculations in the Inter-Fuel Substitution Special Study. These benefits far exceed the costs of coal washing, estimated to be between Rs. 100/tonne and Rs. 150/tonne. As far as existing plants are concerned, delegates at the National Decision Makers' Workshop noted that there are actually very few power plants now in operation which have not been designed to burn poor quality, high ash coal. The Workshop also noted that where the plants have been designed to burn such coal, the advantages of beneficiation to the power plant are not so great. Furthermore, for new and existing plants, the economic benefits of beneficiation can only be realised if power plant designers and operators can be assured of a reliable and continuous supply of washed coal. The current GoI policies, opening the market for coal supply, will allow power plant owners more freedom to shop around for alternative coal sources in the event that the supply of washed coal fails to be met. The choice of coal quality, including washed *vs.* unwashed coal, would then be based upon willingness to pay.

One of the main disadvantages of coal washing lies in the fact that the characteristics of Indian coal make it difficult to separate the mineral matter from the carbon without losing carbon. Two large-scale washeries (*Table 2.77*) expect that the recovery rate of coal will be between 74% and 85%.

A second disadvantage was noted at the National Decision Makers' Workshop, namely that coal beneficiation at the present time is likely to be environmentally damaging at the site of the coal washery. Because carbon will be lost in the washery, there will be larger quantities of waste for disposal. One possibility is to use the waste for backfilling at the mine, although the environmental conditions need to be evaluated at each specific site, and monitoring or mitigation plans fully prepared prior to implementation, as recommended in the Special Study on Ash Management, Disposal and Utilisation. Another option is to burn the washery tailings in a fluidised-bed boiler, but then the amount of ash will be similar to the amount produced in a power plant burning unwashed coal; and emissions to the atmosphere will, at best, be the same as for unwashed coal. However, less coal is transported and more is disposed at the mine. Moreover, given the poor record of compliance with environmental standards and the potentially harmful nature of washery pollution, it is possible that the net impact on the environment will be negative. Due to these environmental impacts associated with coal washing any moves to promote this option should carefully assess the environmental as well as economic costs and benefits.

Finally, a number of technical and economic issues were raised at the National Decision Makers' Workshop which remain to be resolved: for example, the high carbon content of the washery tailings in Indian circumstances gives rise to the possibility of spontaneous combustion.

The above implementation issues suggest that for coal beneficiation to be economically attractive and environmentally benign, the following conditions need to be met:

- new power plants need to be designed to burn better quality coal and need to be able to shop-around for alternative suppliers if their supply fails to conform with the specification; and
- compliance with environmental standards at washeries and power plants needs to be rigorously enforced.

Clean Coal Combustion Technologies

Clean coal combustion technologies have advantages in improving combustion efficiency and reducing emissions to the environment (both through higher efficiencies and also because pollutants can more easily be removed). Their disadvantages lie in higher capital and operating costs, which exceed those of conventional power plants by 10%-15% on a levelised cost basis. The benefits described in *Section 2.7* suggest at best only marginal reductions in ash (none in Bihar and 2% in AP) and CO2 (3-4%) but more substantial impacts on TSP (17% in Bihar, 3% in AP), SO2 (17% in Bihar and 15% in AP) and NOx (8% in Bihar and 10% in AP), against overall increases in present valued system costs (2% in both cases).

Two technologies in particular were investigated during the course of the work: Pressurised Fluidised Bed Combustion (PFBC) and Integrated-Gasification Combined Cycle (IGCC). Other technologies could have been investigated, but were regarded as less feasible in current circumstances. This judgement was shared by the delegates at the National Decision Makers' Workshop and a team from TERI and the Canadian Energy Research Institute (CERI).

It is clear from the analysis that these innovative technologies are not least-cost under present environmental standards in India, and implementation would not proceed on the basis of normal market incentives. If FGD is made a requirement for new power plants burning imported coal, then some of these technologies might become economically attractive, although further work would need to be done to confirm this.

Section 2.7 has shown a clear trade-off between emissions and costs in implementing clean-coal technologies. Funding might be sought from outside India from the Global

Environment Facility (GEF) for pilot projects if there are potential savings in greenhouse gas emissions or as Activities Implemented Jointly (AIJ) under the Kyoto protocol. India is a good target for such pilot studies as it will burn increasing volumes of fossil fuels, but the global warming benefits may not be as cost-effective as for other GHG reduction options.

Ash Utilisation

Of the 62 million tonnes of ash produced in India in 1996/97, only 2-3% was utilised compared with levels of 25% in China and 85% in Germany. The scale of the problem is, however, much less in Germany; although in China, where 55 million tonnes of ash was produced, the scale of the problem is similar.

The discussion of ash utilisation in India has focused on intervention ("command-and-control" measures) to ensure that ash is utilised on a greater scale. This discussion was reflected in the National Decision Makers' Workshop, where there was considerable support for restrictions on the use of clay for brickmaking within a radius of 50 km of power plants. There was also support for schemes involving the free use of land for industries using power station ash, low cost or free electricity and the free delivery of ash to these industries.

The National Synthesis approached the problem in a different way. It noted that in many countries the ash is sold to industry. But the report observes that in India ash supply is huge and industry will not absorb very much of this ash if it is sold. It also calculates that it costs the power industry around US$6/tonne to dispose of ash in ponds and that if industry could take this ash, it would save them up to US$6/tonne. In a competitive market, power plant owners would be willing to pay anything up to US$6/tonne to anyone to take the ash away.

Delegates at the National Decision Makers' Workshop agreed with the statement that the economic potential for ash utilisation had not been fully realised. They reported first, that power station operators are not commercially oriented; and, second, that existing ash disposal and management standards are not enforced, so that the financial cost of ash disposal may be lower than the estimate of US$6/tonne.

The National Decision Makers' Workshop discussed the current requirements issued by Pollution Control Boards for some power plants that ash utilisation should reach 100% within 10 years of the start of operation of a plant. There was agreement that these targets could not be met by all plants. It was also noted that standards are often flouted since sanctions against power plants at the present time are very weak, given the shortage of power supplies.

A number of points can be inferred from the Special Study on Ash Management, Disposal and Utilisation, the discussion at the National Decision Makers' Workshop and the Synthesis Report. Increased ash utilisation is clearly worthwhile. The correct economic level of ash utilisation at individual power plants for India is unknown, but varies considerably, depending on local circumstances (local industry and types of economic activity, availability and cost of other materials, distance between the power plant and users, road and rail networks, etc.). Increased commercialisation of the power sector and introduction of normal business practices should lead to greater incentives for power plant operators to seek alternative uses for ash more aggressively and to pay for the removal and utilisation of ash. However, it may be necessary to build consumer confidence in construction products such as bricks and cement which incorporate ash, even though fly ash bricks and cement have been found to be technically equal or superior to traditional products. Finally, the enforcement of current standards for ash utilisation would also give greater incentives to power plants to encourage ash utilisation: targets for ash utilisation are likely to be ignored unless the targets are achievable and reflect local conditions.

An example of a market-based instrument, based on trade in ash permits, is discussed below.

Market-Based Instruments

Market-based instruments (MBIs) are an attempt to meet environmental objectives by working through market mechanisms. The advantage of MBIs is that they achieve the same objectives at a lower cost to industry and the economy. They are most easily applied when there are few actors and have easily measurable impacts. An example of the possible use of MBIs for the disposal of ash illustrates the approach.

Setting targets for ash utilisation can be seen as equivalent to establishing a supply of permits to dispose of ash. If these ash disposal permits are allocated equally to all new power plants, without reference to local circumstances, then some plants will find it more difficult to meet the targets than other plants. The power plants which find it less difficult to meet the targets might profitably sell some or all of their allocation of permits to the plants which find it more difficult. Those which can more easily meet their targets then increase their utilisation by an amount equal to the volume of permits sold (i.e. reduce their disposal of ash) whilst plants which have purchased permits (because they cannot easily meet their targets) are able increase their level of disposal. The target utilisation is achieved but the total cost of compliance to all power plants is reduced. It should be noted, however, that tradable permits in ash disposal do not overcome localised problems of ash disposal, so that the approach may have only limited applicability.

Nevertheless, tradable permits in ash disposal might offer considerable attractions. The work undertaken as part of the project has highlighted a number of issues which need to be addressed before market based instruments can be introduced (*Section 2.12.4*). Of greatest importance is the need to ensure that the legislative and regulatory framework for administering MBIs is created. It is also necessary that the power plants and companies using market instruments have strong commercial incentives and face hard budget constraints. Without interest in the market, there is little value in using market-based instruments.

Alternative Standards

The work discussed in this Synthesis was not designed to answer questions about the appropriate environmental standards to implement in Indian conditions. As explained in *Section 1.4.1*, the basic approach was to take existing standards as given and to calculate the costs of internalising these standards, by including all the relevant control costs in the prices of inputs. In principle, the environmental impacts of decisions in the power sector could be reduced by implementing more stringent standards than those currently applied in India. The work gave that option only limited attention, by attempting to estimate the incremental costs of implementing the World Bank's new standards for air quality and emissions (*Section* 2.9). Although these standards are more stringent for SO2 and particulates than existing Indian standards, the analytical results suggested that the incremental costs need not be substantial. Mainly, the problem would be encountered on the side of particulates, and particulate control is relatively inexpensive. However, the work deliberately refrained from making any judgement on whether or not these alternative standards should be implemented.

It is important to note that delegates at the National Decision Makers' Workshop agreed that better implementation of existing standards was more important than the adoption of new and stricter standards. In other words, better implementation of monitoring and enforcement procedures and increased responsibility of SEBs to meeting standards, might be of a more immediate benefit.

4.3 *IMPLEMENTATION OF THE DECISION MAKING PROCESS AND TOOL*

Based on the National Decision Makers' and NGO Workshops and experience elsewhere in policy implementation we discuss in this section how:

- power system planners can be made more aware of the concept of formally integrating environmental analysis into the planning process, and the assistance that can be afforded by the decision making tool (*Section* 4.3.1); and
- the tool could be adopted and replicated in other states in India (*Section* 4.3.2).

4.3.1 *Incorporating the Tool and its Outputs into Power Planning*

First, it is necessary to ensure that power system planners are aware of the full range of serious environmental impacts caused by their decisions; and that these impacts can be handled more cost-effectively if they are recognised at the planning stage: Environmental Impact Assessments should be seen as a last resort, to try to manage those damages rather than avoid them in the first place. Second, power system planners should be convinced that the decision-making process and tool developed under this activity can help them to incorporate rigorous environmental analysis into their decisions.

The suite of models, which is the basis for the decision making tool, has several characteristics which do make it suitable for widespread adoption in the decision making process of power utilities.

- It helps decision makers to focus rigorously on environmental impacts and to try to incorporate them into power planning. The discipline of working through the models is as important as the accuracy of the inputs, assumptions and therefore results. In particular, it forces officials to adopt a systematic approach to decision making: debate must focus on inputs and assumptions within a consistent framework.

- It is a flexible tool. It is recognised that the assumptions and detailed approach, whilst they worked well for the two case study states, may have to be adapted to the needs of states with different situations (fuel sources, finances, available technologies, institutional arrangements). Also, as reported during the National Decision Makers' Workshop, data gathering will always be difficult. However, a particularly powerful advantage of using the tool is that the suite's models, assumptions and data inputs can be altered to fit the characteristics and needs of individual states.
- In AP and Bihar some specific software packages were adopted - in particular the A/S Plan least -cost planning model. This software was successfully employed but other software, such as WASP could equally be used without changing the utility of the decision making tool. The aim was to demonstrate the underlying structure required for a model which is found to be robust.

The model will allow decision makers at the state level, perhaps for the first time, to integrate environmental concerns in power planning. As the modellers gain access to better data and build into the model the specific assumptions relevant to their States, the outputs will better reflect the environmental implications of different policy alternatives. At this point in time, the tool can be increasingly used as an objective and transparent basis to inform the debate about implementing various state level environmental policies within power development.

Delegates at the National Decision Makers' and NGO Workshops suggested that the next step should involve holding further national or regional workshops to discuss with Secretaries of Environment and Energy, SEBs, the CEA, MoP and NGO groups the results of the study and the utility and advantages of the suite as a planning tool in order to encourage them to use the model in their States. The discussions can be supported by the circulation of the Executive Summary of the Synthesis Report and the preparation of a Manual for Environmental Decision-Making. The Manual would document, in a practical way, the use of the decision-making process and tool developed under this activity.

4.3.2 *Disseminating the Tool for Use in Other States*

The National Decision Makers Workshop

A first step towards dissemination and government participation was the National Decision Makers' and NGO Workshops, held in Delhi in early May 1998 to discuss:

- the benefit for Indian power policy makers, regulators and utility managers of the tool and how the resulting 'menu of options' and their implications for the environment can be integrated into power policy and planning.
- the replicability of the decision making tool in the context of other states in India and how the model can be disseminated to other states.

The 80 delegates at the National Decision Makers' Workshop, after hearing the presentations of the work, participated in debating the suitability of the findings for the rest of India. The result was positive and many states as well as the national government expressed strong interest in the tool and sought further information on how they could use it and the results it yielded in the two case study states. The delegates put forward several proposals on replicating the use of the tool in other states and how they could take the findings from the activity forward into a next phase of implementation. The 40 delegates at National NGO Workshop similarly urged extension of the work to other States.

Institutional Mechanisms

It is evident that a critical step towards being able to replicate the successes of Andhra Pradesh and Bihar is to build the human resource capacities in each state to use the model and make use of the outputs. This could be done either directly with a suitable agency in the state, e.g. the regulator or grid company in a restructured state electricity system; or with assigned consultants or research institutes. The latter groups could then be contracted to use and run the model, for example on behalf of the regulator or grid company. In this case, the regulator or grid company would still need in-house capacity to manage the consultants and then integrate the results of the model into their indicative power planning.

Methods of Dissemination

Once the concept of using the model is accepted, dissemination will focus on informing and instructing potential users of the model how to operate it. The ongoing activity succeeded in transferring skills to local consultants, using the following approach:

- an initial two week training session in Delhi for modelling teams;
- follow-up and on-the-job training, once the modelling exercise had begun; and
- provision of a User (co-ordination) manual explaining how to tackle various issues relating to the analysis.

The successful output from the case studies indicates the effectiveness of such an approach and this suggests that it can be used in training specialists from the other states.

As stated above, it is now proposed to create Manual for Environmental Decision-Making, based on the experiences of the two case studies.

Joint UNDP/World Bank
ENERGY SECTOR MANAGEMENT ASSISTANCE PROGRAMME (ESMAP)

LIST OF REPORTS ON COMPLETED ACTIVITIES

Region/Country	*Activity/Report Title*	*Date*	*Number*
	SUB-SAHARAN AFRICA (AFR)		
Africa Regional	Anglophone Africa Household Energy Workshop (English)	07/88	085/88
	Regional Power Seminar on Reducing Electric Power System Losses in Africa (English)	08/88	087/88
	Institutional Evaluation of EGL (English)	02/89	098/89
	Biomass Mapping Regional Workshops (English)	05/89	--
	Francophone Household Energy Workshop (French)	08/89	--
	Interafrican Electrical Engineering College: Proposals for Short- and Long-Term Development (English)	03/90	112/90
	Biomass Assessment and Mapping (English)	03/90	--
	Symposium on Power Sector Reform and Efficiency Improvement in Sub-Saharan Africa (English)	06/96	182/96
	Commercialization of Marginal Gas Fields (English)	12/97	201/97
Angola	Energy Assessment (English and Portuguese)	05/89	4708-ANG
	Power Rehabilitation and Technical Assistance (English)	10/91	142/91
Benin	Energy Assessment (English and French)	06/85	5222-BEN
Botswana	Energy Assessment (English)	09/84	4998-BT
	Pump Electrification Prefeasibility Study (English)	01/86	047/86
	Review of Electricity Service Connection Policy (English)	07/87	071/87
	Tuli Block Farms Electrification Study (English)	07/87	072/87
	Household Energy Issues Study (English)	02/88	--
	Urban Household Energy Strategy Study (English)	05/91	132/91
Burkina Faso	Energy Assessment (English and French)	01/86	5730-BUR
	Technical Assistance Program (English)	03/86	052/86
	Urban Household Energy Strategy Study (English and French)	06/91	134/91
Burundi	Energy Assessment (English)	06/82	3778-BU
	Petroleum Supply Management (English)	01/84	012/84
	Status Report (English and French)	02/84	011/84
	Presentation of Energy Projects for the Fourth Five-Year Plan (1983-1987) (English and French)	05/85	036/85
	Improved Charcoal Cookstove Strategy (English and French)	09/85	042/85
	Peat Utilization Project (English)	11/85	046/85
	Energy Assessment (English and French)	01/92	9215-BU
Cape Verde	Energy Assessment (English and Portuguese)	08/84	5073-CV
	Household Energy Strategy Study (English)	02/90	110/90
Central African Republic	Energy Assessement (French)	08/92	9898-CAR
Chad	Elements of Strategy for Urban Household Energy The Case of N'djamena (French)	12/93	160/94
Comoros	Energy Assessment (English and French)	01/88	7104-COM
Congo	Energy Assessment (English)	01/88	6420-COB
	Power Development Plan (English and French)	03/90	106/90
Côte d'Ivoire	Energy Assessment (English and French)	04/85	5250-IVC
	Improved Biomass Utilization (English and French)	04/87	069/87
	Power System Efficiency Study (English)	12/87	--
	Power Sector Efficiency Study (French)	02/92	140/91
	Project of Energy Efficiency in Buildings (English)	09/95	175/95

Region/Country	*Activity/Report Title*	*Date*	*Number*
Ethiopia	Energy Assessment (English)	07/84	4741-ET
	Power System Efficiency Study (English)	10/85	045/85
	Agricultural Residue Briquetting Pilot Project (English)	12/86	062/86
	Bagasse Study (English)	12/86	063/86
	Cooking Efficiency Project (English)	12/87	--
	Energy Assessment (English)	02/96	179/96
Gabon	Energy Assessment (English)	07/88	6915-GA
The Gambia	Energy Assessment (English)	11/83	4743-GM
	Solar Water Heating Retrofit Project (English)	02/85	030/85
	Solar Photovoltaic Applications (English)	03/85	032/85
	Petroleum Supply Management Assistance (English)	04/85	035/85
Ghana	Energy Assessment (English)	11/86	6234-GH
	Energy Rationalization in the Industrial Sector (English)	06/88	084/88
	Sawmill Residues Utilization Study (English)	11/88	074/87
	Industrial Energy Efficiency (English)	11/92	148/92
Guinea	Energy Assessment (English)	11/86	6137-GUI
	Household Energy Strategy (English and French)	01/94	163/94
Guinea-Bissau	Energy Assessment (English and Portuguese)	08/84	5083-GUB
	Recommended Technical Assistance Projects (English & Portuguese)	04/85	033/85
	Management Options for the Electric Power and Water Supply Subsectors (English)	02/90	100/90
	Power and Water Institutional Restructuring (French)	04/91	118/91
Kenya	Energy Assessment (English)	05/82	3800-KE
	Power System Efficiency Study (English)	03/84	014/84
	Status Report (English)	05/84	016/84
	Coal Conversion Action Plan (English)	02/87	--
	Solar Water Heating Study (English)	02/87	066/87
	Peri-Urban Woodfuel Development (English)	10/87	076/87
	Power Master Plan (English)	11/87	--
	Power Loss Reduction Study (English)	09/96	186/96
Lesotho	Energy Assessment (English)	01/84	4676-LSO
Liberia	Energy Assessment (English)	12/84	5279-LBR
	Recommended Technical Assistance Projects (English)	06/85	038/85
	Power System Efficiency Study (English)	12/87	081/87
Madagascar	Energy Assessment (English)	01/87	5700-MAG
	Power System Efficiency Study (English and French)	12/87	075/87
	Environmental Impact of Woodfuels (French)	10/95	176/95
Malawi	Energy Assessment (English)	08/82	3903-MAL
	Technical Assistance to Improve the Efficiency of Fuelwood Use in the Tobacco Industry (English)	11/83	009/83
	Status Report (English)	01/84	013/84
Mali	Energy Assessment (English and French)	11/91	8423-MLI
	Household Energy Strategy (English and French)	03/92	147/92
Islamic Republic of Mauritania	Energy Assessment (English and French)	04/85	5224-MAU
	Household Energy Strategy Study (English and French)	07/90	123/90
Mauritius	Energy Assessment (English)	12/81	3510-MAS
	Status Report (English)	10/83	008/83
	Power System Efficiency Audit (English)	05/87	070/87

Region/Country	*Activity/Report Title*	*Date*	*Number*
Mauritius	Bagasse Power Potential (English)	10/87	077/87
	Energy Sector Review (English)	12/94	3643-MAS
Mozambique	Energy Assessment (English)	01/87	6128-MOZ
	Household Electricity Utilization Study (English)	03/90	113/90
	Electricity Tariffs Study (English)	06/96	181/96
	Sample Survey of Low Voltage Electricity Customers	06/97	195/97
Namibia	Energy Assessment (English)	03/93	11320-NAM
Niger	Energy Assessment (French)	05/84	4642-NIR
	Status Report (English and French)	02/86	051/86
	Improved Stoves Project (English and French)	12/87	080/87
	Household Energy Conservation and Substitution (English and French)	01/88	082/88
Nigeria	Energy Assessment (English)	08/83	4440-UNI
	Energy Assessment (English)	07/93	11672-UNI
Rwanda	Energy Assessment (English)	06/82	3779-RW
	Status Report (English and French)	05/84	017/84
	Improved Charcoal Cookstove Strategy (English and French)	08/86	059/86
	Improved Charcoal Production Techniques (English and French)	02/87	065/87
	Energy Assessment (English and French)	07/91	8017-RW
	Commercialization of Improved Charcoal Stoves and Carbonization Techniques Mid-Term Progress Report (English and French)	12/91	141/91
SADC	SADC Regional Power Interconnection Study, Vols. I-IV (English)	12/93	--
SADCC	SADCC Regional Sector: Regional Capacity-Building Program for Energy Surveys and Policy Analysis (English)	11/91	--
Sao Tome and Principe	Energy Assessment (English)	10/85	5803-STP
Senegal	Energy Assessment (English)	07/83	4182-SE
	Status Report (English and French)	10/84	025/84
	Industrial Energy Conservation Study (English)	05/85	037/85
	Preparatory Assistance for Donor Meeting (English and French)	04/86	056/86
	Urban Household Energy Strategy (English)	02/89	096/89
	Industrial Energy Conservation Program (English)	05/94	165/94
Seychelles	Energy Assessment (English)	01/84	4693-SEY
	Electric Power System Efficiency Study (English)	08/84	021/84
Sierra Leone	Energy Assessment (English)	10/87	6597-SL
Somalia	Energy Assessment (English)	12/85	5796-SO
South Africa Republic of	Options for the Structure and Regulation of Natural Gas Industry (English)	05/95	172/95
Sudan	Management Assistance to the Ministry of Energy and Mining	05/83	003/83
	Energy Assessment (English)	07/83	4511-SU
	Power System Efficiency Study (English)	06/84	018/84
	Status Report (English)	11/84	026/84
	Wood Energy/Forestry Feasibility (English)	07/87	073/87
Swaziland	Energy Assessment (English)	02/87	6262-SW
	Household Energy Strategy Study	10/97	198/97
Tanzania	Energy Assessment (English)	11/84	4969-TA
	Peri-Urban Woodfuels Feasibility Study (English)	08/88	086/88
	Tobacco Curing Efficiency Study (English)	05/89	102/89
	Remote Sensing and Mapping of Woodlands (English)	06/90	--
	Industrial Energy Efficiency Technical Assistance (English)	08/90	122/90

Region/Country	***Activity/Report Title***	***Date***	***Number***
Tanzania	Power Loss Reduction Volume 1: Transmission and Distribution SystemTechnical Loss Reduction and Network Development (English)	06/98	204A/98
	Power Loss Reduction Volume 2: Reduction of Non-Technical Losses (English)	06/98	204B/98
Togo	Energy Assessment (English)	06/85	5221-TO
	Wood Recovery in the Nangbeto Lake (English and French)	04/86	055/86
	Power Efficiency Improvement (English and French)	12/87	078/87
Uganda	Energy Assessment (English)	07/83	4453-UG
	Status Report (English)	08/84	020/84
	Institutional Review of the Energy Sector (English)	01/85	029/85
	Energy Efficiency in Tobacco Curing Industry (English)	02/86	049/86
	Fuelwood/Forestry Feasibility Study (English)	03/86	053/86
	Power System Efficiency Study (English)	12/88	092/88
	Energy Efficiency Improvement in the Brick and Tile Industry (English)	02/89	097/89
	Tobacco Curing Pilot Project (English)	03/89	UNDP Terminal Report
	Energy Assessment (English)	12/96	193/96
Zaire	Energy Assessment (English)	05/86	5837-ZR
Zambia	Energy Assessment (English)	01/83	4110-ZA
	Status Report (English)	08/85	039/85
	Energy Sector Institutional Review (English)	11/86	060/86
	Power Subsector Efficiency Study (English)	02/89	093/88
	Energy Strategy Study (English)	02/89	094/88
	Urban Household Energy Strategy Study (English)	08/90	121/90
Zimbabwe	Energy Assessment (English)	06/82	3765-ZIM
	Power System Efficiency Study (English)	06/83	005/83
	Status Report (English)	08/84	019/84
	Power Sector Management Assistance Project (English)	04/85	034/85
	Power Sector Management Institution Building (English)	09/89	--
	Petroleum Management Assistance (English)	12/89	109/89
	Charcoal Utilization Prefeasibility Study (English)	06/90	119/90
	Integrated Energy Strategy Evaluation (English)	01/92	8768-ZIM
	Energy Efficiency Technical Assistance Project: Strategic Framework for a National Energy Efficiency Improvement Program (English)	04/94	--
	Capacity Building for the National Energy Efficiency Improvement Programme (NEEIP) (English)	12/94	--

EAST ASIA AND PACIFIC (EAP)

Asia Regional	Pacific Household and Rural Energy Seminar (English)	11/90	--
China	County-Level Rural Energy Assessments (English)	05/89	101/89
	Fuelwood Forestry Preinvestment Study (English)	12/89	105/89
	Strategic Options for Power Sector Reform in China (English)	07/93	156/93
	Energy Efficiency and Pollution Control in Township and Village Enterprises (TVE) Industry (English)	11/94	168/94
	Energy for Rural Development in China: An Assessment Based on a Joint Chinese/ESMAP Study in Six Counties (English)	06/96	183/96
Fiji	Energy Assessment (English)	06/83	4462-FIJ

Region/Country	*Activity/Report Title*	*Date*	*Number*
Indonesia	Energy Assessment (English)	11/81	3543-IND
	Status Report (English)	09/84	022/84
	Power Generation Efficiency Study (English)	02/86	050/86
	Energy Efficiency in the Brick, Tile and Lime Industries (English)	04/87	067/87
	Diesel Generating Plant Efficiency Study (English)	12/88	095/88
	Urban Household Energy Strategy Study (English)	02/90	107/90
	Biomass Gasifier Preinvestment Study Vols. I & II (English)	12/90	124/90
	Prospects for Biomass Power Generation with Emphasis on Palm Oil, Sugar, Rubberwood and Plywood Residues (English)	11/94	167/94
Lao PDR	Urban Electricity Demand Assessment Study (English)	03/93	154/93
Malaysia	Sabah Power System Efficiency Study (English)	03/87	068/87
	Gas Utilization Study (English)	09/91	9645-MA
Myanmar	Energy Assessment (English)	06/85	5416-BA
Papua New Guinea	Energy Assessment (English)	06/82	3882-PNG
	Status Report (English)	07/83	006/83
	Energy Strategy Paper (English)	--	--
	Institutional Review in the Energy Sector (English)	10/84	023/84
	Power Tariff Study (English)	10/84	024/84
Philippines	Commercial Potential for Power Production from Agricultural Residues (English)	12/93	157/93
	Energy Conservation Study (English)	08/94	--
Solomon Islands	Energy Assessment (English)	06/83	4404-SOL
	Energy Assessment (English)	01/92	979-SOL
South Pacific	Petroleum Transport in the South Pacific (English)	05/86	--
Thailand	Energy Assessment (English)	09/85	5793-TH
	Rural Energy Issues and Options (English)	09/85	044/85
	Accelerated Dissemination of Improved Stoves and Charcoal Kilns (English)	09/87	079/87
	Northeast Region Village Forestry and Woodfuels Preinvestment Study (English)	02/88	083/88
	Impact of Lower Oil Prices (English)	08/88	--
	Coal Development and Utilization Study (English)	10/89	--
Tonga	Energy Assessment (English)	06/85	5498-TON
Vanuatu	Energy Assessment (English)	06/85	5577-VA
Vietnam	Rural and Household Energy-Issues and Options (English)	01/94	161/94
	Power Sector Reform and Restructuring in Vietnam: Final Report to the Steering Committee (English and Vietnamese)	09/95	174/95
	Household Energy Technical Assistance: Improved Coal Briquetting and Commercialized Dissemination of Higher Efficiency Biomass and Coal Stoves (English)	01/96	178/96
Western Samoa	Energy Assessment (English)	06/85	5497-WSO

SOUTH ASIA (SAS)

Bangladesh	Energy Assessment (English)	10/82	3873-BD
	Priority Investment Program (English)	05/83	002/83
	Status Report (English)	04/84	015/84
	Power System Efficiency Study (English)	02/85	031/85
	Small Scale Uses of Gas Prefeasibility Study (English)	12/88	--

Region/Country	*Activity/Report Title*	*Date*	*Number*
India	Opportunities for Commercialization of Nonconventional Energy Systems (English)	11/88	091/88
	Maharashtra Bagasse Energy Efficiency Project (English)	07/90	120/90
	Mini-Hydro Development on Irrigation Dams and Canal Drops Vols. I, II and III (English)	07/91	139/91
	WindFarm Pre-Investment Study (English)	12/92	150/92
	Power Sector Reform Seminar (English)	04/94	166/94
	Environmental Issues in the Power Sector	06/98	205/98
Nepal	Energy Assessment (English)	08/83	4474-NEP
	Status Report (English)	01/85	028/84
	Energy Efficiency & Fuel Substitution in Industries (English)	06/93	158/93
Pakistan	Household Energy Assessment (English)	05/88	--
	Assessment of Photovoltaic Programs, Applications, and Markets (English)	10/89	103/89
	National Household Energy Survey and Strategy Formulation Study: Project Terminal Report (English)	03/94	--
	Managing the Energy Transition (English)	10/94	--
	Lighting Efficiency Improvement Program Phase 1: Commercial Buildings Five Year Plan (English)	10/94	--
Sri Lanka	Energy Assessment (English)	05/82	3792-CE
	Power System Loss Reduction Study (English)	07/83	007/83
	Status Report (English)	01/84	010/84
	Industrial Energy Conservation Study (English)	03/86	054/86

EUROPE AND CENTRAL ASIA (ECA)

Bulgaria	Natural Gas Policies and Issues (English)	10/96	188/96
Central and Eastern Europe	Power Sector Reform in Selected Countries	07/97	196/97
Eastern Europe	The Future of Natural Gas in Eastern Europe (English)	08/92	149/92
Kazakhstan	Natural Gas Investment Study, Volumes 1, 2 & 3	12/97	199/97
Kazakhstan & Kyrgyzstan	Opportunities for Renewable Energy Development	11/97	16855-KAZ
Poland	Energy Sector Restructuring Program Vols. I-V (English)	01/93	153/93
Portugal	Energy Assessment (English)	04/84	4824-PO
Romania	Natural Gas Development Strategy (English)	12/96	192/96
Turkey	Energy Assessment (English)	03/83	3877-TU

MIDDLE EAST AND NORTH AFRICA (MNA)

Arab Republic of Egypt	Energy Assessment (English)	10/96	189/96
Morocco	Energy Assessment (English and French)	03/84	4157-MOR
	Status Report (English and French)	01/86	048/86
	Energy Sector Institutional Development Study (English and French)	07/95	173/95
Syria	Energy Assessment (English)	05/86	5822-SYR
	Electric Power Efficiency Study (English)	09/88	089/88
	Energy Efficiency Improvement in the Cement Sector (English)	04/89	099/89
	Energy Efficiency Improvement in the Fertilizer Sector (English)	06/90	115/90

Region/Country	*Activity/Report Title*	*Date*	*Number*
Tunisia	Fuel Substitution (English and French)	03/90	--
	Power Efficiency Study (English and French)	02/92	136/91
	Energy Management Strategy in the Residential and Tertiary Sectors (English)	04/92	146/92
	Renewable Energy Strategy Study, Volume I (French)	11/96	190A/96
	Renewable Energy Strategy Study, Volume II (French)	11/96	190B/96
Yemen	Energy Assessment (English)	12/84	4892-YAR
	Energy Investment Priorities (English)	02/87	6376-YAR
	Household Energy Strategy Study Phase I (English)	03/91	126/91

LATIN AMERICA AND THE CARIBBEAN (LAC)

LAC Regional	Regional Seminar on Electric Power System Loss Reduction in the Caribbean (English)	07/89	--
	Elimination of Lead in Gasoline in Latin America and the Caribbean (English and Spanish)	04/97	194/97
	Elimination of Lead in Gasoline in Latin America and the Caribbean - Status Report (English and Spanish)	12/97	200/97
	Harmonization of Fuels Specifications in Latin America and the Caribbean (English and Spanish)	06/98	203/98
Bolivia	Energy Assessment (English)	04/83	4213-BO
	National Energy Plan (English)	12/87	--
	La Paz Private Power Technical Assistance (English)	11/90	111/90
	Prefeasibility Evaluation Rural Electrification and Demand Assessment (English and Spanish)	04/91	129/91
	National Energy Plan (Spanish)	08/91	131/91
	Private Power Generation and Transmission (English)	01/92	137/91
	Natural Gas Distribution: Economics and Regulation (English)	03/92	125/92
	Natural Gas Sector Policies and Issues (English and Spanish)	12/93	164/93
	Household Rural Energy Strategy (English and Spanish)	01/94	162/94
	Preparation of Capitalization of the Hydrocarbon Sector	12/96	191/96
Brazil	Energy Efficiency & Conservation: Strategic Partnership for Energy Efficiency in Brazil (English)	01/95	170/95
	Hydro and Thermal Power Sector Study	09/97	197/97
Chile	Energy Sector Review (English)	08/88	7129-CH
Colombia	Energy Strategy Paper (English)	12/86	--
	Power Sector Restructuring (English)	11/94	169/94
	Energy Efficiency Report for the Commercial and Public Sector (English)	06/96	184/96
Costa Rica	Energy Assessment (English and Spanish)	01/84	4655-CR
	Recommended Technical Assistance Projects (English)	11/84	027/84
	Forest Residues Utilization Study (English and Spanish)	02/90	108/90
Dominican Republic	Energy Assessment (English)	05/91	8234-DO
Ecuador	Energy Assessment (Spanish)	12/85	5865-EC
	Energy Strategy Phase I (Spanish)	07/88	--
	Energy Strategy (English)	04/91	--

Region/Country	*Activity/Report Title*	*Date*	*Number*
Ecuador	Private Minihydropower Development Study (English)	11/92	--
	Energy Pricing Subsidies and Interfuel Substitution (English)	08/94	11798-EC
	Energy Pricing, Poverty and Social Mitigation (English)	08/94	12831-EC
Guatemala	Issues and Options in the Energy Sector (English)	09/93	12160-GU
Haiti	Energy Assessment (English and French)	06/82	3672-HA
	Status Report (English and French)	08/85	041/85
	Household Energy Strategy (English and French)	12/91	143/91
Honduras	Energy Assessment (English)	08/87	6476-HO
	Petroleum Supply Management (English)	03/91	128/91
Jamaica	Energy Assessment (English)	04/85	5466-JM
	Petroleum Procurement, Refining, and Distribution Study (English)	11/86	061/86
	Energy Efficiency Building Code Phase I (English)	03/88	--
	Energy Efficiency Standards and Labels Phase I (English)	03/88	--
	Management Information System Phase I (English)	03/88	--
	Charcoal Production Project (English)	09/88	090/88
	FIDCO Sawmill Residues Utilization Study (English)	09/88	088/88
	Energy Sector Strategy and Investment Planning Study (English)	07/92	135/92
Mexico	Improved Charcoal Production Within Forest Management for the State of Veracruz (English and Spanish)	08/91	138/91
	Energy Efficiency Management Technical Assistance to the Comision Nacional para el Ahorro de Energia (CONAE) (English)	04/96	180/96
Panama	Power System Efficiency Study (English)	06/83	004/83
Paraguay	Energy Assessment (English)	10/84	5145-PA
	Recommended Technical Assistance Projects (English)	09/85	--
	Status Report (English and Spanish)	09/85	043/85
Peru	Energy Assessment (English)	01/84	4677-PE
	Status Report (English)	08/85	040/85
	Proposal for a Stove Dissemination Program in the Sierra (English and Spanish)	02/87	064/87
	Energy Strategy (English and Spanish)	12/90	--
	Study of Energy Taxation and Liberalization of the Hydrocarbons Sector (English and Spanish)	120/93	159/93
Saint Lucia	Energy Assessment (English)	09/84	5111-SLU
St. Vincent and the Grenadines	Energy Assessment (English)	09/84	5103-STV
Trinidad and Tobago	Energy Assessment (English)	12/85	5930-TR

GLOBAL

	Energy End Use Efficiency: Research and Strategy (English)	11/89	--
	Women and Energy--A Resource Guide The International Network: Policies and Experience (English)	04/90	--
	Guidelines for Utility Customer Management and Metering (English and Spanish)	07/91	--
	Assessment of Personal Computer Models for Energy Planning in Developing Countries (English)	10/91	--
	Long-Term Gas Contracts Principles and Applications (English)	02/93	152/93

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GLOBAL (Continuation)

Comparative Behavior of Firms Under Public and Private Ownership (English)	05/93	155/93
Development of Regional Electric Power Networks (English)	10/94	--
Roundtable on Energy Efficiency (English)	02/95	171/95
Assessing Pollution Abatement Policies with a Case Study of Ankara (English)	11/95	177/95
A Synopsis of the Third Annual Roundtable on Independent Power Projects: Rhetoric and Reality (English)	08/96	187/96
Rural Energy and Development Roundtable (English)	05/98	202/98

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