ESM293

Environmental Issues in the Power Sector:

Long-Term Impacts and Policy Options for Karnataka

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Preface

Electricity plays a critical role in economic development and in reducing poverty. But the production and use of electricity also has the potential of generating adverse environment impacts if not managed properly. Recognizing the links between electricity development and the environment, the Bank, in cooperation with the Government of India and the state governments of Karnataka and Rajasthan, implemented assessments of environmental policies in the Power Sector in the Indian states of Karnataka and Rajasthan. This work is designed to examine and quantify a broad number of options for reducing the environmental impacts of power development in general and power reform in particular. The strategic objective is to provide the analytical basis for assisting the states of Karnataka and Rajasthan to develop power sector policies and strategies that are environmentally sustainable.

These assessments are a follow-up to the broader study of Environmental Issues in the Power Sector (EIPS), funded by United Kingdom's Department for International Development (UKDFID). This work concluded, inter alia, that power sector reform is the most effective option to manage the adverse environmental impacts of power development because of the incentives it provides for improving efficiency in the production and use of power; and for implementing mitigation options in combination to maximize the impact. The EIPS work was completed in 2000 with a set of dissemination workshops in several Indian states as well as in Delhi.

While the main purpose is to present a long-term strategic options for the power sector that take into account environmental aspects, it is also meant to validate both the methodology developed under EIPS, and its main conclusions. While validating the robustness of the methodology developed under EIPS, the assessments reinforce the conclusion of EIPS that power sector reform and restructuring generate local and global environmental benefits in addition to the more generally recognized economic, financial and customer service benefits. These environmental benefits promote better health and improved quality of life.

The conclusions were presented at workshops in Rajasthan and Karnataka that brought together a wide audience of stake-holders, including decision-makers, technical staff of the public sector energy and environment institutions, power regulator, the power utilities, and NGOs. The goal of the workshops was to raise awareness about the environmental impacts of power development in general and the reform program in particular; and about options to mitigate those impacts. The workshops also provided a forum for exchanging ideas about the possibilities and implications for implementing the findings of the work.

Following the dissemination workshop, a short capacity building program was provided in both states. This program introduced: the basic concepts involved in carrying out the environmental and economic analysis of power development, and the fundamentals of the

analytical tools and process to conduct the analysis. It was attended by technical staff representing the public sector energy and environment institutions, the power regulator, and the generation, transmission and distribution companies.

The main counter-parts for the activity were the Energy Departments of the state governments of Karnataka and Rajasthan. The World Bank managed the work, with Mudassar Imran as the task manager; and contributed part of the funding through the South Asia Region. The main source of funding was the Energy Sector Management Assistance Program (ESMAP).

Acknowledgments

This report was prepared by International Energy and Development Associates (IDEA) and Energy, Economy and Environment Consultants (EEEC) of Bangalore, India. Mr. Mudassar Imran was the Task Manager. Debra Trent, Fowzia Hassan, and Matthew Gardner provided invaluable assistance in preparing the report. Marjorie Araya from ESMAP coordinated the publication process.

ESMAP and the South Asia Region are indebted to a many individuals and organizations involved in completing this activity. However, a special acknowledgement is necessary to the many government officials for their support and guidance throughout the study implementation period. In Karnataka, the State Secretary of Energy and his staff; the management and staff of the generation, transmission and distribution companies; members of the Environmental Advisory Committee; and at the center, officials of the Ministry of Power; the Department of Economic Affairs, and the Ministry of Finance, all played a critical role in contributing to the success of the work. Finally, a vote of thanks is due to Ms. Fanny Kathinka Missfeldt-Ringius, and Mr. Ernesto Sanchez-Triana for reviewing the reports and providing detailed comments, and many staff at the World Bank for timely advice and commenting on the work as it progressed.

Abbreviations and Acronyms

ADB	Asian Development Bank
AEH	All-electric homes
AIC	Average incremental cost (a proxy for LRMC)
AP	Andhra Pradesh
APL	Adaptable program loan
ASCI	Administrative Staff College of India (Hyderabad)
BAU	Business as usual
BESCOM	Bangalore Energy Supply Company
CCCT	Combined-cycle combustion turbine
CDM	Clean Development Mechanism (of the Kyoto Protocol)
CEA	Central Electricity Authority (Ministry of Power, Government of India)
CFBC	Circulating fluidized bed combustion
CIF	Cost, insurance, and freight
CRZ	Coastal Regulatory Zone (as defined by MoEF)
Cumec	Cubic meters per second
DFID	Department for International Development (UK)
DISCO	Electricity distribution Company
DSM	Demand-side management
EIPS	Environmental Issues in the Power Sector
ESCO	Energy supply company
ESP	Electrostatic precipitator
FGD	Flue gas desulfurization
FOB	Free on board
GAR	gross as received
GDP	gross domestic product
GDSP	gross state domestic product
GEF	Global Environment Facility
GESCOM	Gulbarga Energy Supply Company
GHG	Greenhouse gas
GO	Government order

GoI	Government of India
GoK	Government of Karnataka
GW	Gigawatt (10^9 W)
HESCOM	Hubli Energy Supply Company
HSD	High-speed diesel oil
HT	High tension
HP	Horsepower
HVDC	High-voltage direct current (transmission)
ICB	International competitive bidding
IDC	Interest during construction
IPCC	Intergovernmental Panel on Climate Change (IPCC)
IPP	Independent power producer
IRR	Internal rate of return (to equity investors)
JCC	Japan Crude Cocktail
KEB	Karnataka Electricity Board
KERC	Karnataka Electricity Regulatory Commission
KPCL	Karnataka Power Company Limited
KPTCL	Karnataka Power Transmission Company Limited
LNG	Liquefied natural gas
LOLP	Loss of load probability
LPD	Liters per day
LRMC	Long-run marginal cost
LT	Low tension
MCM	Million cubic meters
MESCOM	Mangalore Energy Supply Company
Mbtu	Million British Thermal Units
MNES	Ministry of Non-Conventional Energy Sources
MoEF	Ministry of Environment and Forests
MoU	Memorandum of understanding
mtpy	Million tons per year
NPC	Nuclear Power Corporation
NPV	Net present value
NTPC	National Thermal Power Corporation
OPEC	Organisation of Petroleum Exporting Countries

PAF	Project-affected family
PCF	Prototype Carbon Fund
PIP	Project Implementation Plan
PPA	Power purchase agreement correct!
PPP	Purchasing power parity
PTC	Power trading corporation
R&R	Resettlement and relocation
RR	Revenue requirements
SCADA	Sone Command Area Development Authority (Bihar)
SEB	State Electricity Board
SLD	Straight-line depreciation
T&D	Transmission and distribution
TRANSCO	(Power) transmission company
TSP	Total suspended particulate matter
UP	Uttar Pradesh
VVNL	Visvesvaraya Vidyuth Migama Ltd

Units of Measure

1 kCal = 3.968 British Thermal Units (Btus)

Currency Equivalents

US$1 = Rs 48

Executive Summary

1. This study of the long-term environmental impacts and policy options for power sector development in Karnataka is one of a series undertaken by the World Bank in cooperation with the Government of India and state governments. It is a follow-up to the broader study Environmental Issues in the Power Sector (EIPS) (ESMAP/World Bank 1998).

2. The general methodology developed for EIPS, described in detail in the EIPS Manual for Environmental Decision-Making (ESMAP/World Bank 1999), is used for this analysis. The primary distinguishing feature of the methodology is the application of rigorous tools for power systems planning to determine the least-cost configuration for a given scenario. Estimates of the environmental impacts are then based upon this configuration. For the Karnataka case study, the EIPS methodology was implemented with Enviroplan, a model expressly designed for multi-attribute planning studies capable of examining a large number of options and scenarios and tightly integrated with economic benefit-cost, financial, and multi-attribute trade-off analysis.

3. The study begins by evaluating the impacts of the baseline reform scenario and then perturbs this scenario for the options examined, including a scenario of "stalled reform," to enable assessment of the costs and benefits of reform. Because Karnataka has already implemented significant reform measures, "no reform" (as used in the original 1998 EIPS study) is not a useful scenario. Each of the options and scenarios is evaluated on the following attributes:

- tariff (quantified as the average levelized tariff over the planning horizon)
- economic efficiency (quantified as the net present value (NPV) of the net economic benefits)
- reliability (quantified as the NPV of unserved energy)
- environmental objectives (including minimization of greenhouse gas (GHG) emissions, acid rain precursors, health damage due to air emissions, and so forth)
- consumptive water use (Karnataka being a drought-prone state)
- government revenue (magnitude of subsidies required, or dividends received)

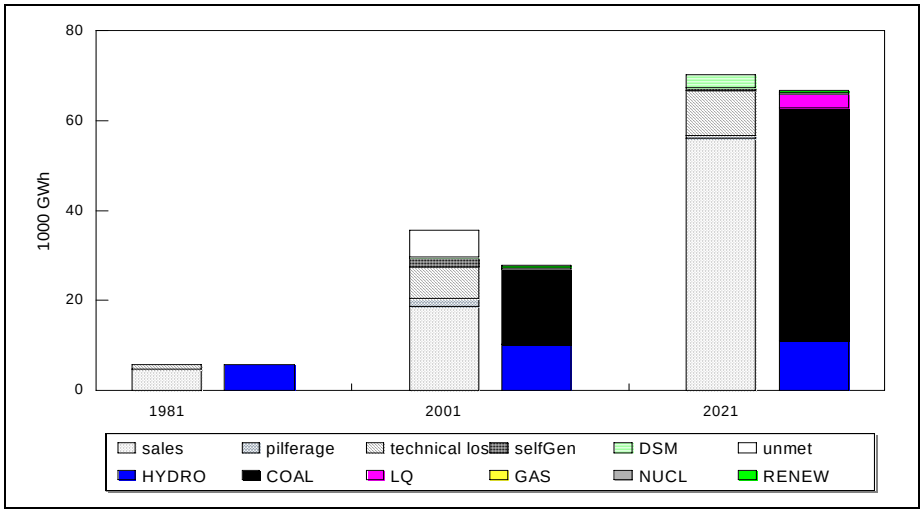
4. The environmental impacts are expressed both as physical attributes (e.g., tons PM-10, namely particulate matter of 10 microns diameter or smaller emitted, or lifetime GHG emissions, etc.) and as environmental damage costs, assessed based on a recent World Bank study of Bombay (Lvovsky *et al*., 2000). While the limitations of the benefit transfer method are recognized, the monetization of damage costs provides a useful additional dimension to the economic analysis. The critical insight of this study is that the damage costs (expressed in rupees per kilogram) of emissions from grid-based fossil plants, which generally are located in remote locations and are relatively easy to

monitor and enforce, are between one and two orders of magnitude smaller than those of captive and self-generation units, emissions from which are essentially uncontrolled and occur in more populated areas at or near ground level.

The Long-Term Prospects

5. Karnataka's exposure to drought is significant and the demand for consumptive surface water use for irrigation is steadily increasing. This is a major concern given the disputes over water use in both the Krishna and Cauvery river basins. The Government of Karnataka (GoK) has given primacy in water allocation to irrigation, raising a fundamental problem for power plant siting. If the use of coastal sites on the west coast is constrained by environmental concerns over the impact of air emissions on the ecologically sensitive forest areas of the Western Ghats, as witnessed by the disputes in the late 1990s over the proposed Cogentrix project at Mangalore, and if the use of inland sites is constrained by the issue of water allocation, how then is the state's need for additional base load power plants to be accommodated?

Figure 1: The Long-Term Outlook for Karnataka?



6. Karnataka's power in 1981 was supplied entirely by hydro plants, but with most of the central sector contribution fossil-based, hydro today accounts for only about one-third of generation (Figure 1). Overall generation is inadequate, resulting in much unmet demand and obliging significant self-generation. The fundamental problem is that if, as seems likely, the addition of further hydro generation remains highly constrained, the bulk of the additional generation that must be added over the next 20 years must be some combination of fossil, renewables, and demand-side management (DSM)—which under a "business-as-usual" scenario would most likely be coal. A significant proportion of this coal capacity could be located in other states, such as Orissa and Tamil Nadu, and conveyed to Karnataka by high-voltage direct current (HVDC), but the environmental effects associated with such projects should still be counted to Karnataka's account (and

the exporting states may well attempt to recover these costs in the form of higher royalties). Gas-based generation may be an alternative, given the new offshore finds in Andhra Pradesh (AP) and the prospects of a major gas pipeline crossing northern Karnataka, but whether this would be economically viable would depend on the gas pricing policy of the national government.

7. Such a coal future is described in various studies by the Central Electricity Authority (CEA) of the Indian Ministry of Power, but most notably in a 1999 study of the long-term future of the all-India power sector (CEA 1999). The study, conducted in connection with the 2,000MW Talcher Stage II project that provides for an HVDC link to Bangalore, identified three major HVDC links as being least-cost for India as a whole by 2015, with more than 5,000MW to be transmitted to southern India by 2015. The Talcher II project is underway but progress on the other projects has been slow. There are well-recognized problems associated with bringing such large projects to reality.

8. The coal-by-wire option would shift from Karnataka to the producing states the environmental impacts that are associated with coal generation. It may well be that the producing states will as a result have to impose much higher coal royalties (typical coal royalties are Rs 90/ton, or about 10 percent of the production cost of an F grade coal priced at Rs 870/ton).[1] It is also likely that coal-producing areas would encounter water resource constraints: while Karnataka is a drought-prone state for which the opportunity costs of consumptive use are higher than in the eastern states of Bihar and Orissa, it is unclear if mine-mouth projects in Bihar and Orissa could serve the bulk of the power needs of both southern and northern India in the decade 2010–2020.

Major Findings

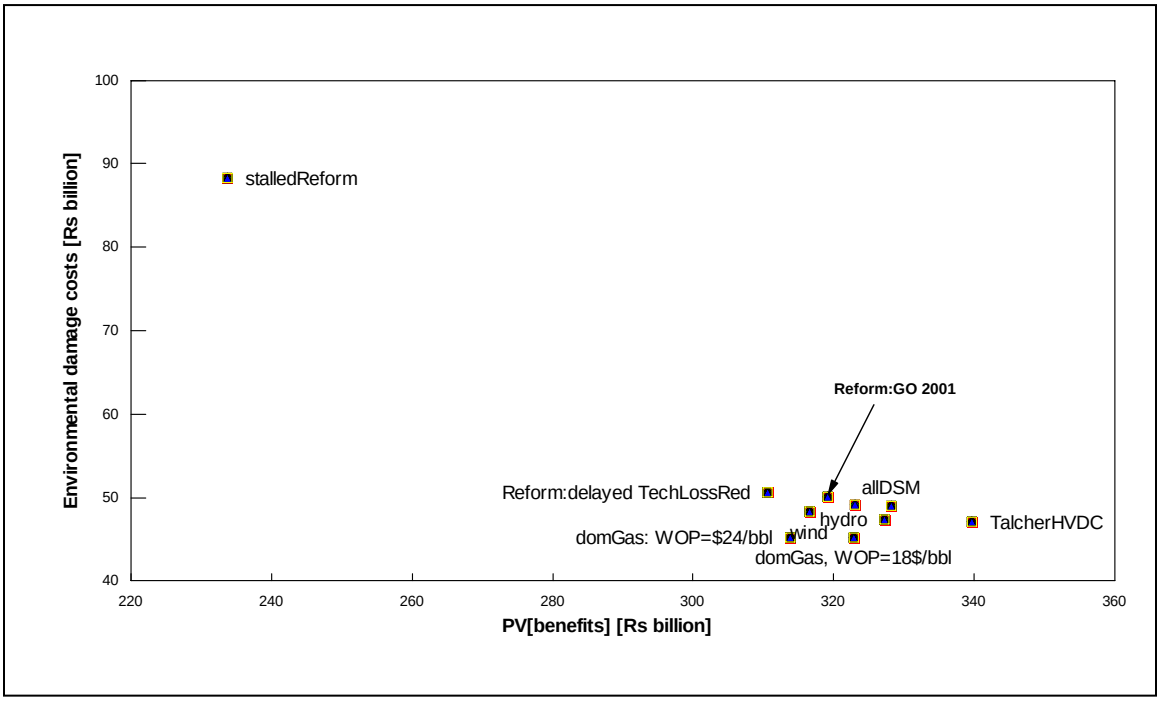
9. The major findings of this study may be summarized as follows:

- Power sector reform is the single most important step that may be taken to mitigate the environmental impacts of the power sector. The difference in emissions (and damage costs) between reform and stalled reform far exceeds the difference across all other options, such as DSM or the use of renewables (see Figure 2).[2]

[1] For this reason, this study considers not just the environmental impacts of power generation within Karnataka, but also of power projects in states that could serve Karnataka.

[2] Part of the explanation is that stalled reform results in the failure to realize the benefits of variables such as no further decrease in rates of technical or nontechnical transmission and distribution (T&D) loss reduction; no further changes in (real) tariffs; no independent power producers (IPPs) reaching financial closure; and no trading of short-term surplus/deficits with the Power Trading Corporation (PTC).

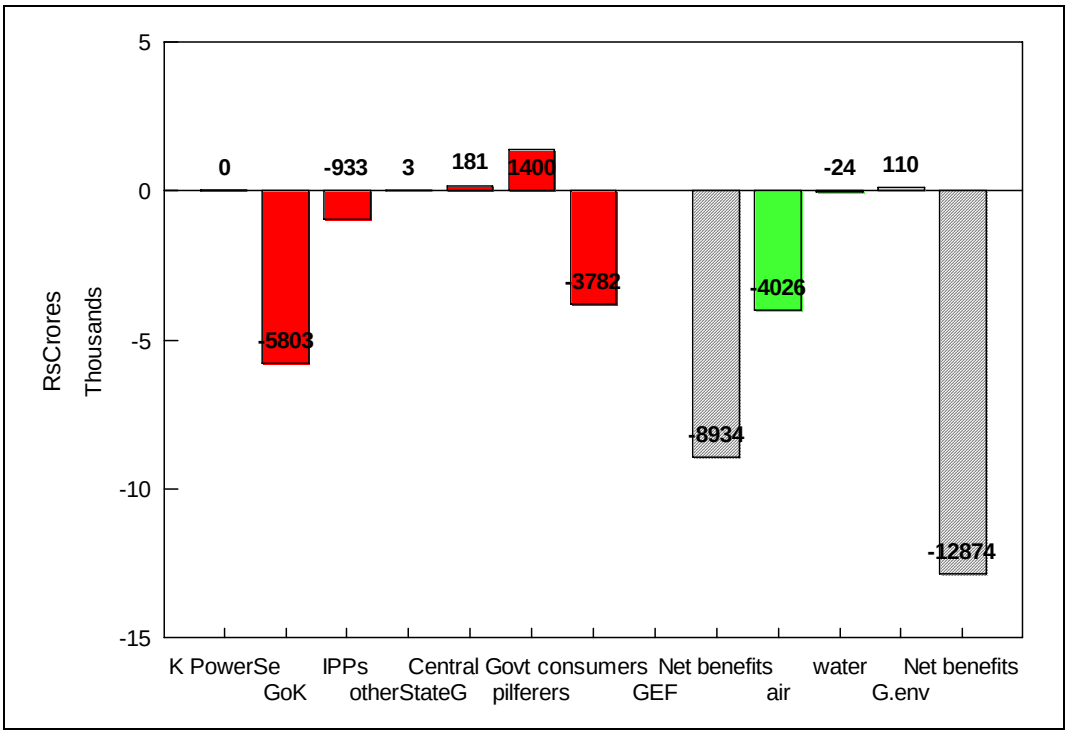
Figure 2: Environmental Damage Costs Versus Net Economic Benefits
(Net Present Value, in Rs 10 millions)



- Figure 3 illustrates the findings of the distributional analysis done for each of the options and scenarios examined. Each bar represents the financial impact on the stakeholder, with taxes and transfer payments aggregated to yield the total economic benefit. The further addition of environmental benefits yields the social net benefit.[3] Consumers are divided into two groups: those who pay the extant tariff, and pilferers. The only significant winners of stalled reform are the pilferers, who would benefit from the failure to further reduce non-technical losses. Unless the reforms progress to completion, all other stakeholders, including the environment, would lose.

[3] GHG emissions are valued on the basis of an avoided carbon cost of US$15/ton.

Figure 3: Stalled Reform--Distribution of Costs and Benefits



- Tariff reform is the second most important policy option for environmental sustainability. In most states, even with reform the projected tariff structure (that is, the relative price for each consumer category) would far from match the cost of supply. This remains true even if the overall level of the tariff is increased to levels that restore creditworthiness. If price-elastic behavior is factored into a tariff structure reform in which the high-tension (HT) tariff is below the average tariff, industrial consumption increases and agricultural consumption decreases, improving the incentives for DSM and resulting in a shift to less water-intensive cropping patterns and to better water management techniques. This effect is multiplied by higher transmission and distribution (T&D) losses for low-tension transmission (LT), even when T&D losses are at economically optimal levels.

- Demand-side management is win-win. The priority for DSM should be in the subsidized sectors (agriculture and household), as every kWh that is not sold to these sectors implies a financial gain to the power companies. There is much potential for private sector participation through energy supply companies (ESCOs). Unlike other options such as the importation of coal or gas, which require actions and negotiations with other parties, initiating DSM programs furthermore

is entirely within the control of decision-makers in the individual states.

- Over the long term, meeting peak power requirements will become the main issue. If reform is successful, the system load factor will actually decrease, meaning that the system will need a larger share of peaking and intermediate load plants than most states currently envisage. In the short term, the 2003 Electricity Act will improve the utilization of existing plants. Because Raichur performs substantially better than the national average, it will benefit from market liberalization by being able to export freely to other states or to power trading corporations if asked to back down by Karnataka. From the national perspective, better utilization of the more efficient plants is environmentally desirable.
- Consumptive water use for thermal generation is a major issue in Karnataka. Gas combined-cycle combustion turbines (CCCTs), which are attractive for their relatively low air emissions, consume only one-third of the water that a steam-cycle project uses.
- The fear of some officials that the open-access provisions of the 2003 Electricity Act will permit captive units to increase their generation and to trade to third parties, thus eroding the revenue stream from the highest-paying customers and increasing environmental damage costs, is unfounded. As long as the national government maintains its diesel-pricing policy, the variable costs of diesel-based generation will continue to exceed the HT industrial tariff.
- Given the sensitivity of hydro projects in the Western Ghats, the potential for new large hydro schemes is limited. The Krishna hydro schemes at Almatti, Tammankal, and Jurala are economically viable and environmentally benign (since the dams are already in place for irrigation and the bulk of the resettlement, relocation, and environmental costs are sunk, but are impeded by interstate water disputes with Krishna.
- The least-cost thermal option is mine-mouth generation in eastern India (Orissa), with transmission to the south by HVDC (as in the first such project, Talcher II, which is being implemented by the National Thermal Power Corporation (NTPC)).
- The use of imported coal would be a viable option for Karnataka if the existing customs duty on imported coal were to be removed. Coastal sites have the advantage of requiring no consumptive use of freshwater, and, subject to clearance from the Ministry of the Environment and Forests, there is no bar to the siting of power plants on the west coast provided that they lie outside the immediate 500-meter coastal zone and that their foreshore facilities are outside zone I.

- The tariff for renewable projects such as wind and small hydro is being renegotiated with independent power producers (IPPs). The Karnataka Power Transmission Company Ltd has advised that the standard Ministry of Nonconventional Energy Sources tariff of Rs 3.50/kWh is not sustainable. This study shows that the probable capital cost decreases for wind power would still permit an acceptable rate of return for developers, but that the pace of new projects may slow as only the best sites will warrant development under the new tariff.

1

Introduction

Background

1.1 The World Bank is implementing a study program of the environmental issues facing the power sector of India. The objective of the program is to identify environmentally sustainable development options for the sector and to demonstrate the linkages between policy choices and long-term changes in the environment.

1.2 Comprehensive case studies of Andhra Pradesh (Administrative Staff College 1998) and Bihar (SCADA 1998) were completed in early 1998, and a first synthesized report was published later that year as part of the World Bank Environmental Issues in the Power Sector (EIPS) study (ESMAP/World Bank 1998). A smaller study of Haryana that applied the EIPS methodology was completed in 1999 (IDEA 1999), and two further studies are being conducted in 2003: that of Karnataka (described in this report) and a similar study of Rajasthan. The Haryana, Karnataka, and Rajasthan assessments lack the comprehensive supporting background studies of the original AP and Bihar assessments.[4]

1.3 The scope of EIPS and of this study is limited to assessment of the policy options for grid-connected electricity and of the environmental issues associated with these options. There are many related issues that undoubtedly are important, such as the environmental impacts associated with indoor air pollution from cooking fuels or kerosene lighting, but these lie outside the terms of reference agreed with the Government of India. The renewable energy options considered in this report are those whose main role is supply into the grid (wind, bagasse cogeneration, small hydro) or direct substitution into the grid (for example, the displacement of geysers by solar water heaters), rather than those that have a decentralized rural application, such as the use of biogas or the replacement of kerosene lighting by photovoltaic-based solar systems.

[4] For this reason, the Haryana assessment was termed a "rapid assessment." The original studies now underway for Karnataka and Rajasthan were also denoted rapid assessment in light of their similar approach. However, the term "rapid assessment" has a specific meaning within the statutory process of environmental clearance and is therefore not used in the title of the study.

1.4 The objective is to identify the major options for power sector development in Karnataka and the main environmental concerns associated with each. Several important points need to be raised at the outset, for they serve to highlight how this study differs from others.

1.5 First, this is not a study of the environmental problems at existing projects. That subject was addressed by a 2000–2001 MECON study, the results of which are available in the report "Rapid Environmental Audit and Outline Compliance Program" (MECON/Knight Piesold 2001).[5]

1.6 This is also not a study of the financial implications of power sector reform and restructuring, of the institutional dimension of reform. Nor does it discuss the specific details of controversial IPP projects in Karnataka, some of which, such as that involving the Cogentrix project on the west coast, have important environmental dimensions.

1.7 This is a study of long-term options, a perspective that is often lost in the debate due to the urgency of short-term problems. The sort of long-term strategic issues addressed here are best illustrated by example:

- As a consequence of the Dabhol fiasco,[6] the use in India of liquefied natural gas (LNG) for power generation is being questioned. However, a significant share of the problems at Dabhol are related to ENRON and the unique circumstances of the project's gestation, rather than on the fuel itself. Many of the environmental concerns raised by the Cogentrix project (and the potential impact of sulfur emissions on the unique forest environment of the Western Ghats) would be resolved by LNG. The long transportation distances for domestic coal to western coastal Karnataka make the use of imported fuels at this location relatively attractive. Two questions need to be addressed: What should be the long-term policy of the State Government of Karnataka (GoK) on fuel choices at western coastal locations, and what would be the long-term environmental consequences of these choices?

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[5] MECON was charged with reviewing the environmental performance and compliance status of existing facilities and with carrying out rapid environmental audits of all thermal plants generating more than 20MW(e). It also audited a sample of smaller plants and T&D facilities.

[6] The Dabhol power generation project in Maharashtra is the largest foreign IPP in India, sponsored by Enron under a memorandum of understanding (MoU). The history of the project has been one of continuous controversy over the high tariff, the lack of competition, allegations of corruption, lack of transparency, cancellation and subsequent renegotiation of the project, and litigation. The project was to have been based on LNG, but the first 740MW phase started operation in 1997 using instead naphtha, pending completion of the second 1,444MW phase and the resolution of the LNG contracts. The second phase was almost complete when construction stopped in May 2001 following nonpayment by the Maharashtra State Electricity Board of US$240 million in outstanding power purchase bills: the subsequent collapse of Enron has resulted in disarray and confusion as the various stakeholders attempt to find ways of restarting the project.

- The main policy issue raised by the Cogentrix controversy[7] is not whether this specific project had unacceptable environmental impacts (nor is it whether the statutory procedures for environmental protection had been followed: this issue was resolved when the Supreme Court of India threw out the lawsuit in question).[8] Rather, it is whether environmental policy should be made by IPPs and the courts or by the GoK. In this particular instance the decision to include flue gas desulfurization (FGD) in the design was made by the IPP, in the mistaken belief that this would head off litigation and not because statutory environmental regulations so required. The ambient sulfur dioxide (SO_2) standards that in fact apply to the Mangalore location would not have required FGD. The additional costs of FGD were simply factored into the proposed PPA, increasing the cost of power generation. If the GoK wishes to prohibit coal plants on the west coast or to require additional environmental protection measures beyond the existing statutory requirements, it should have an express power plant siting policy to reflect this view. Absent such a proactive policy, it is inevitable that others will attempt to resolve the issues in court, as a consequence aggravating power shortages through delay.
- Karnataka is poorly endowed with coal. Its only coal-fired plant is at Raichur, supplied by coal from other states. But the expansion of Raichur as a source is constrained by a range of issues, not the least of which being its limited supply of consumptive water for cooling. Imported coal is subject to 29.5 percent duty, rendering it uneconomic, except possibly for blending purposes at plants subject to stringent SO_2 emission standards.[9]

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[7] The Cogentrix project (named after its original U.S. sponsor) was to be sited in Mangalore on Karnataka's west coast and was to use imported coal. As with the Dabhol project, it was sponsored under an MoU arrangement. The project has suffered from endless controversy due to lack of transparency, a controversial power purchase agreement (PPA) that was renegotiated several times, and allegations of corruption (eventually thrown out by the courts).

[8] Cynics would respond that this particular "public interest" environmental litigation was just a convenient vehicle by which opponents of the project could exert pressure by delay (a tactic that in fact succeeded as Cogentrix withdrew from the project a short time before the Supreme Court ruled). However, there is no question that the project raised valid questions about environmental impacts—the main issues of which being how and by whom these questions should be settled, and based on what criteria.

[9] For example, the proposed 660MW Vijayawada Stage IV project in AP, for which the German Kreditanstalt fuer Wiederaufbau (KfW) is considering finance, would be required to use very low sulfur Indonesian imported coal (about 3 percent of total annual requirement) to ensure compliance with the World Bank sulfur emissions limit for the Vijayawada project. This remains true even were the entire project to be supplied with washed coal.

- But what are the consequences of increased competition in the coal sector? If the GoI were to lower import duty to the 1998 level of 10 percent, what would be the consequences for Karnataka's coal plants, both at Raichur and on the west coast? Even if coal washing were to bring the ash content of domestic coal to 34 percent, this level is still two to three times higher than that of imported coal. Imported coal would bring major relief to the problem of ash disposal.
- The 2003 Electricity Act introduces some fundamental changes into the power sector, notably by allowing generating companies to sell to third parties. This would allow, for example, generating companies such as Karnataka Power Company Ltd (KPCL) to sell to the Power Trading Corporation (PTC) or other state electricity boards (SEBs). Should payment from these potential customers be more immediately forthcoming than from the Karnataka TRANSCO (KPTCL), there is a clear likelihood of this happening.[10]
- The Electricity Act also permits open access to the transmission grid. This will enable captive units to sell power to third parties without hindrance, thus introducing the possibility that sales by the distribution companies (DISCOs) to the highest tariff industrial customers will fall. However, the extent to which this would occur in practice is strongly dependent upon the diesel fuel pricing policy of the GoI.
- The National Thermal Power Corporation (NTPC) is India's premier power generation company. Its proposal for the Talcher II project, that includes an HVDC link to the Bangalore area, presents for Karnataka a completely new option for electricity supply. NTPC is eager to expand its role as a supplier to the states, as evidenced by discussions for the expansion of the 1,000MW Simhadri plant, which currently serves AP exclusively. This raises the option of out-of-state generation plants taking an increased role in Karnataka's power sector: from Karnataka's perspective this would be environmentally favorable, but there is also the implication that the exporting states sooner or later would attempt to extract higher royalties.
- It is widely understood that investment in T&D has lagged behind investment in generation, in Karnataka as elsewhere, and upgradation and improvement of the subtransmission and distribution network is a key part of restoring financial viability to the power sector.[11] While most of the short-term emphasis is on remedial work and the reduction

[10] The key provision is Section 10 (2), which states that "A generating company may supply electricity to any licensee in accordance with this Act and the rules and regulations made thereunder and may, subject to the regulations made under subsection (2) of section 42, supply electricity to any consumer."

[11] In Karnataka over the past decade, capital investment in generation and T&D has been in the ratio 6–1.8 to 1, as against the general target of 6–3 to 3%.

of commercial losses, what should be the long-term target for technical losses? Less than 15 percent is often mentioned as a target, but how much less?

- Karnataka has substantial unexploited large-hydro potential, but its exploitation is constrained by environmental concerns in the western zone and by trade-offs in irrigation and interstate water disputes on the major Krishna and Cauvery rivers in northern and southern Karnataka, respectively.[12] But if further large hydro schemes are not possible, and coal projects on the west coast are constrained by objections that range from the impact of air emissions on forests to the impact of transmission corridors on biodiversity, what remains? A proliferation of small, liquid-fuel plants inevitably located near urban and industrial load centers, whose air emissions are arguably of greater health impact than those of coal plants at remote locations?
- What are the opportunities for Karnataka to profit from a range of possible mechanisms related to climate change, including potential projects suitable for implementation under the Clean Development Mechanism (CDM) of the Kyoto Protocol, the Prototype Carbon Fund (PCF), or carbon trading? Unless the GoK undertakes a proactive role in seeking out such opportunities, they will pass to others. What are these opportunities for Karnataka, and what are their costs and benefits?
- Steam-cycle fossil-fuelled generation consumes substantial quantities of water for cooling (dependent upon heat rate). A coal-fired plant requires about 3.75 liters/kWh. At coastal sites this is not an issue, since once-through cooling or seawater cooling towers may be employed. At sites in the interior, however, this is a significant concern, particularly given Karnataka's exposure to drought and the increasing demands for consumptive water use that are due to irrigation.
- Although progress on demand-side management (DSM) options has been modest, many of these have low investment requirements and short gestation periods, and offer quick payback. Some of these DSM options require only a third of the capital investment per MW of new generation capacity.

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[12] A Supreme Court ruling limits the operating height of the Almatti dam to elevation 519.6 meters. While this constraint may not have affected the installed capacity at the proposed Almatti power project (298MW), the dry-season energy output is significantly diminished by the reduction of the planned power storage capacity (the operating height of the dam was originally set at elevation 524 meters, and the downstream cascade of a further 900–1,000MW is not viable at all without significant power storage at Almatti).

- Electricity is the preferred source of energy for heating bathing water. The consumption of high-grade and expensive energy for such a low-grade application is thermodynamically and economically unacceptable. The reasons that this practice persists are the perceived high initial cost of a solar hot water system (in the region of Rs 25,000, although low-cost loans are available) and the lack of information about the solar alternative. This domestic use of electricity is largely responsible for the morning peak, which is sometimes larger than the evening peak.
- The domestic sector is also responsible for the evening peak, the culprit in this case being the ubiquitous incandescent light bulb. This consumes four times the power consumed by an equivalent CFL (compact fluorescent lamp), but continues to be favored, due largely to its low first cost.
- Tube lights are popular in commercial applications and to a limited extent in domestic applications. Most of these tube lights use inefficient iron core chokes that consume 13–15W of power for a 40W tube light, thus raising the total consumption to about 54W. An electronic choke uses less than 1W and thus would save 13W for every tube light. Again, ignorance of the benefit of the more efficient alternative and the high first cost are the major issues constraining uptake. A concentrated policy to replace old chokes with new electronic chokes would significantly reduce the peak load.
- Inefficient agricultural pump-sets constitute a well-known area of inefficiency, and the quantity of electricity used by this sector is high. The average pump efficiency is only about 20 percent, yet most pumps could easily be replaced by a smaller, 40-percent-efficient pump that would deliver the same quantity of water. The problem in this case is that farmers receive essentially free power (or power charged at a flat rate for which cost is unrelated to consumption) and therefore have no incentive to adopt the more efficient pump. A way must be found to tap this potential energy saving, perhaps through third-party financing.
- Renewable energy producers have in recent years benefited from a relatively generous tariff that in particular has encouraged the development of small hydro and wind power generation. Based on the original 1994 Ministry of Nonconventional Energy Sources (MNES) guideline that provided for a price of Rs 2.25/kWh escalated at 5 percent per year, the tariff in 2003 would be Rs 3.49/kWh—substantially higher than average acquisition costs of around Rs 2.50/kWh. Because of the financial pressures that these high purchase prices were beginning to impose on KPTCL, negotiations were started with the developers and a new agreement was reportedly reached in early May 2003 that would limit the tariff to levels more affordable to KPTCL. While this would lead to savings for KPTCL and its

consumers, the key issue for this study is the extent to which lower prices may limit renewable energy development.

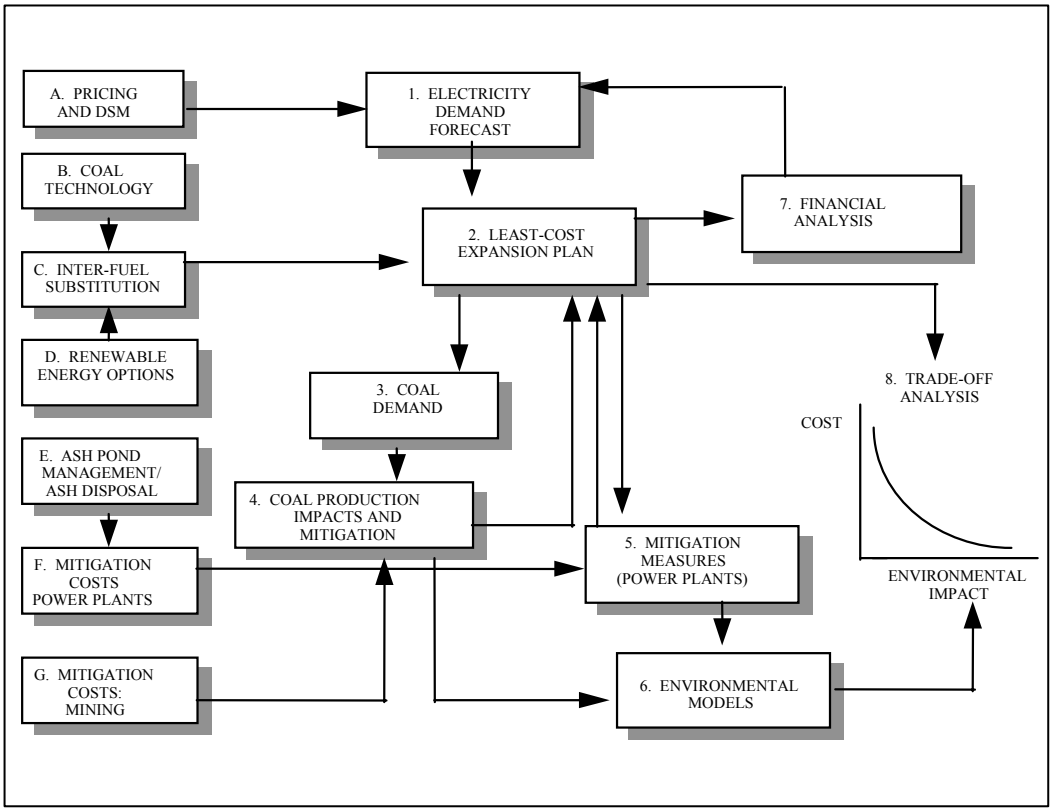
- The distinguishing feature of most of these issues is that their resolution involves trade-offs, although many may be win-win. The purpose of this study is not to resolve the trade-offs but is to develop the information in a form, including the benefit of transparent and quantitative indicators, such that these trade-offs may be more easily made by policymakers and government.
- The emphasis in this study is the quantification of energy–environmental trade-offs, but not all aspects of their resolution are quantifiable. The basic presumptions of the analysis presented here are that environmental standards are being met and that adequate monitoring and enforcement procedures are in effect. The existing fossil-fuel generating stations in Karnataka are generally in environmental compliance, but other EIPS case studies have underscored the importance of the relationship between proper maintenance of pollution control equipment and the financial condition of the plant owner: generating companies that find themselves in acute financial stress rarely have the resources to put sufficient emphasis on environmental considerations.

Study Methodology: Overview

1.8 The study methodology developed for EIPS is summarized in the synthesis report and elaborated in some detail in the Manual for Environmental Decision-Making (ESMAP/World Bank 1999). Its distinguishing feature is the application of rigorous tools for power systems planning that determine the least-cost configuration for a given scenario, upon which are then based estimates of the environmental impacts.[13] Figure 1.1 shows the general scheme: the special studies shown on the left (A to G) were conducted in 1997 as part of the original EIPS study, while the steps on the right are implemented in each state case study.

[13] The question of the best methodological approach for EIPS and its case studies was discussed at a seminar of Indian and international experts in Delhi in late 1996. General Equilibrium Models were considered for the overall modeling framework, but the consensus view was that a bottom-up power systems optimization approach was preferable, given the specific focus on power sector policies at the state level.

Figure 1.1: The EIPS methodology



1.9 The first step is to define the criteria by which the trade-off analysis is to be conducted, for which we have selected the following:

- Economic *efficiency*. This is the traditional objective of power system planning, which attempts to find that power sector development path (or "capacity expansion plan") that minimizes the economic cost of meeting a given load forecast over some planning horizon (usually quantified as net present value (NPV) at a discount rate set equal to the opportunity cost of capital).[14]
- Financial burden on government. A primary objective of Indian power sector reform is to reverse the large government subsidies of the past. In the case of Karnataka, it is estimated that reform will reduce annual (revenue) subsidies from Rs 17.78 billion in fiscal 2002 to zero by fiscal 2006 (GoI 2001).

[14] In the earlier EIPS studies this objective was captured by the present value (PV) of system costs to meet a given load forecast. This ensures the economic optimum only if the level of benefits remains unchanged. When different options have different levels of unserved demand, implying a change of consumer benefits, then one must either adjust the PV of system costs by the change in benefits, or express the entire analysis in terms of economic benefits. This is discussed further in Section 3.

- Supply quality. The trade-off between reliability and cost is important in traditional power systems planning, but in the context of power sector reform it is more important still. Improving the reliability of supply to the consumer is one of the main objectives of reform.
- Tariff level. In the short run the dominant tariff issues—among which the level of the agricultural tariff stands foremost—are how to balance the tariffs among the various consumer groups and how to reduce the extent of cross-subsidies between them. These are short-to-medium-term issues that lie beyond the scope of this study, however. For the study we need a single measure that can capture the main impact on average tariff level, and for which we can calculate the revenue requirements (based on zero subsidy and 16 percent return on equity) divided by units sold, and appropriately levelized.[15]
- Consumptive water use. Total consumptive freshwater use is calculated based on assumptions about consumption at different types of plant.[16]
- Local environmental impacts. In the original EIPS study design, local environmental impacts were captured by the simple proxy of emissions, assuming compliance with existing environmental standards. Thus emissions are calculated for total suspended particulates (TSP), SO_2, nitrous oxides (NOx), and solid waste, treated .
- *Greenhouse gas (GHG) emissions.* As an objective, the reduction of GHG emissions is quite different from the reduction of local environmental impacts. The economic damages that result from local air, water, and solid waste emissions in Karnataka fall largely on Karnataka itself (although the costs of acid rain precursors SO_2 and NO_x to some extent also fall on other states), and are critically dependent upon location. However, the damages caused by GHG emissions are independent of the location of their source, and therefore the simple attribute of lifetime GHG emissions serves as the relevant measure.

Table 1.1 summarizes the way in which each of these attributes is quantified in this study. The issues of how some environmental costs are internalized, while others are accounted for as externalities, are discussed in Section 3.

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[15] Although we use the aggregate average levelized tariff as the main attribute, it should be noted that the model has a detailed representation of sales, tariffs, and nontechnical losses disaggregated by major consumer class (domestic, commercial, low-tension industrial, agricultural, high-tension industrial, and so forth).

[16] Coal plants may be assumed to consume 3.75liters/kWh; nuclear plants 4.5liters/kWh; combined cycle plants 1.5 liters./kWh (since a typical 100MW CCCT has 60MW of combustion turbine and a 40MW steam cycle unit).

Table 1.1: Attribute Definition

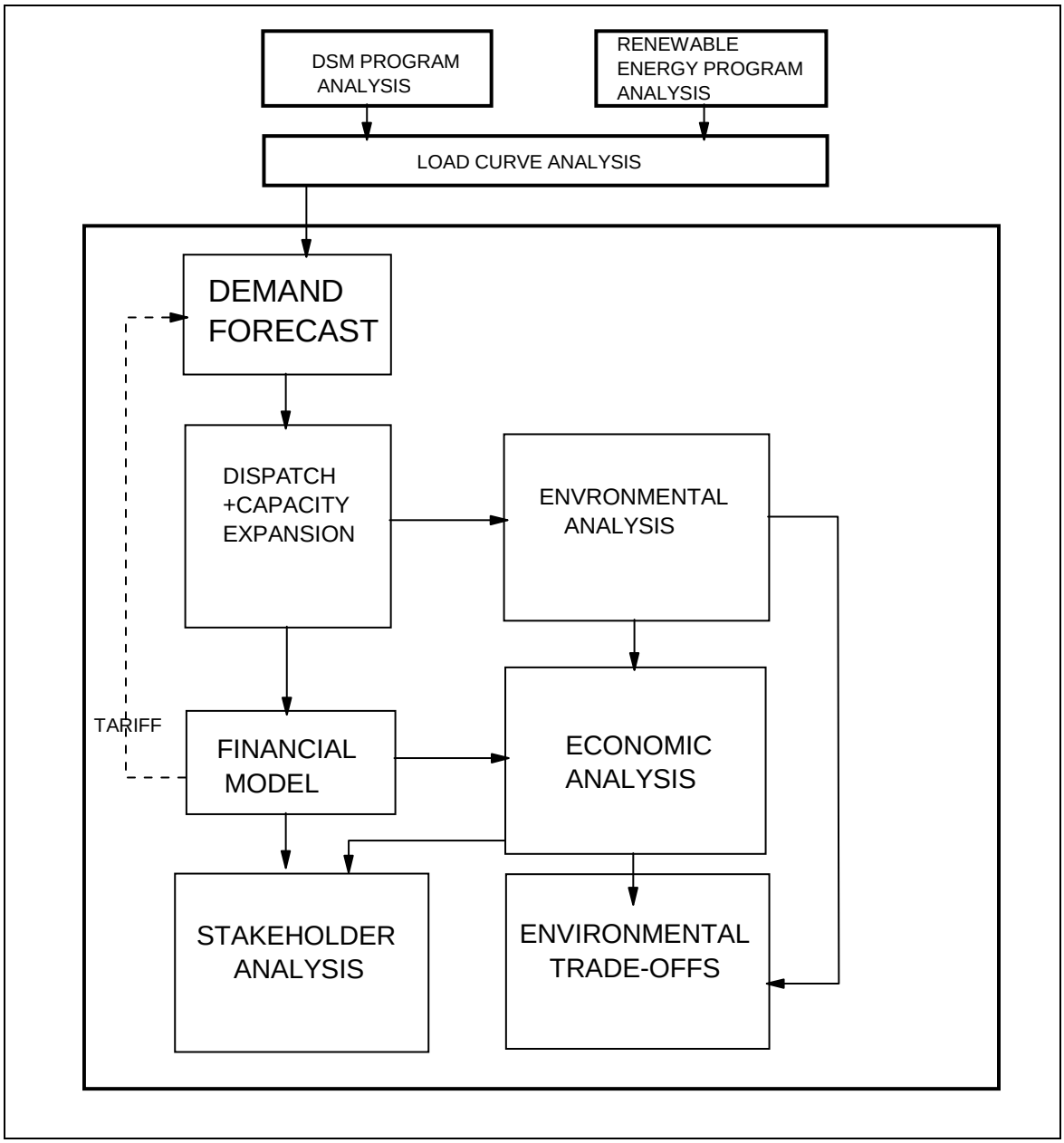
Attribute	Measure	Discussion	Where calculated in the modeling framework (see Figure 1.2)
Economic efficiency	NPV (economic benefits)	See text, Section 3	ECONOMIC ANALYSIS MODEL
Supply quality	PV (unserved energy)	While generation loss of load probability (LOLP) is often used to express generation reliability, unserved energy at the consumer is a better indicative criterion (particularly where most of the interruptions experienced by consumers are related to distribution system failures)	DISPATCH MODEL
Government subsidy	PV (government subsidies required)	This is calculated as the cash subsidy required to balance annual revenue requirements	FINANCIAL MODEL
Tariff level	Levelized average tariff (Rs/kWh)		FINANCIAL MODEL
Local air emissions	(i) Emissions attributes (as PV of tons/year) (ii) PV of annual damage costs	Damage cost estimates based on the World Bank Six Cities Study (see Section 3 for details)	DISPATCH MODEL (damage costs in ENVIRONMENTAL ANALYSIS)
Consumptive water use	PV (quantity) as millions cubic meters/year		DISPATCH MODEL
GHG emissions	(i) undiscounted tons of carbon over the planning horizon (ii) discounted emissions	Undiscounted emissions are used for consistency with GEF practice. However, there are consistency problems with a criterion whose numerator is undiscounted and whose denominator is discounted. Results therefore are also displayed in discounted terms, so that avoided costs can be stated in terms consistent with other objectives	DISPATCH MODEL

1.10 For this case study, the EIPS methodology is implemented with Enviroplan, a model expressly designed for multi-attribute planning studies capable of examining large number of options and scenarios, and is tightly integrated with benefit cost and multi-attribute trade-off analyses resident in the master spreadsheet. Enviroplan has been used in numerous applications over the past few years,[17] including BC Hydro (Canada), Sri Lanka (GHG overlay study), Haryana (Economic Analysis of World Bank

[17] The best introductory documentation is *Introduction to Enviroplan, Workshop Workbook* (British Columbia Hydro 1996) or Appendix F of the *Integrated Energy Plan* (British Columbia Hydro 1995). The model is also described in *Incorporating Environmental Concerns into Power Sector Decision-Making: A Case Study of Sri Lanka* (Meier and Munasinghe 1994).

Reform Program), and Andhra Pradesh (USAID integrated resource plan and the World Bank economic analysis of the power sector reform program. Figure 1.2 provides an overview of the major building blocks of the model.

Figure 1.2: The Enviroplan Model



1.11 The modeling sequence begins with specification of existing DSM programs and renewable energy projects (analyzed in their own independent spreadsheets). These are considered as perturbations of the load curve; the load curve impacts are also assessed in a special spreadsheet. This information is passed to the demand forecast, which can take user-specified forecasts (such as that of the 2001

Government Order) or can build its own forecast based on price and income elasticities (prices are passed in a feedback loop from the financial model).

1.12 A major issue in load forecasting is the treatment of unserved grid demand, part of which is met by captive generation in the industrial sector or by inferior substitutes such as kerosene for lighting or diesel self-generation in the commercial and domestic sector, and part of which remains unserved (and which therefore entails loss of consumer surplus).[18]

1.13 Reduction of unserved demand is also one of the main objectives of power sector reform: much of the present shortage can be attributed to insufficient generation because finance for new projects cannot be obtained in the state of crisis in which most SEBs find themselves. Reform leads to financially healthy sector institutions, which in turn removes many of the financing constraints, allowing the grid supply to serve the full demand. Since the environmental impacts of emissions from diesel self-generation are substantially higher than those from grid generation, it is necessary to model these details of unserved demand if the environmental benefits of reform are to be properly captured (see also Table 3.1).

1.14 The dispatch and capacity expansion module then determines the capacity expansion plan and dispatch requirements to meet the demand forecast. In the event of constraints (for example, in the case of stalled reform the demand cannot be fully satisfied because IPPs cannot obtain financial closure), some part of the unserved demand is met by self-generation, also assessed in this module.

1.15 The environmental analysis calculates the environmental residuals, such as air emissions, consumptive water use, and solid waste, based on the corresponding fuel consumption (and assumptions about pollution controls, heat rates, and so forth).

1.16 One of the major methodological issues is the treatment of environmental effects associated with imports and exports. Clearly, for Karnataka the most desirable option from an environmental perspective would be for the state to import all of its electricity from Orissa by HVDC line. This would not make for a very useful study if that were the main conclusion, however, and the EIPS methodology accordingly requires consideration of the environmental impacts of all electricity consumed by the state, even if the source of supply is out of state. The model therefore keeps track of imports and

[18] The most important point to note, and one that is often ignored, is that the unserved demand is an output of the modeling process, not an input assumption. Where supply is constrained, the unserved demand thus emerges as the difference between the total demand and what can be supplied under extant financial constraints (such as the escrow capacity, in the case of potential IPP projects). The total unserved demand then has to be allocated across the demand sectors by some policy assumption, such as "no cuts to agriculture," and the residual calculated for each. Assumptions are then necessary about how this demand not served by the grid is reconciled—captive generation, self-generation, or simply not met—which implies a change (loss) in benefits. Such unserved demand must be valued (most conservatively at the tariff, better at the estimated loss of consumer surplus), and added to the total system cost. Failure to make this calculation results in an underestimate of the economic benefits of reform.

exports of electricity and the location of generation, and the summary reconciliation of economic and environmental costs separately identifies out-of-state impacts.

1.17 The financial model calculates the revenue requirements necessary to meet the investment program and operating costs of the identified supply configuration. It is assumed that revenue subsidies are phased out in some target year, after which the tariff is endogenously determined by apportioning the annual revenue requirements to the various tariff categories, and determining the tariff for each group by dividing by kWh sold. This requires additional information about the desired structure of the tariffs (that is, the relation of domestic to industrial to agricultural tariffs), while the level of the tariff is determined by overall revenue requirements and by assumptions about the equity returns.

1.18 The financial situation of the Karnataka electricity sector is complex, and subject to many uncertainties. Fortunately, detailed financial modeling of all of the unbundled corporations created in the first step of reform is unnecessary for our purposes, since much of the difficult detail relates to the management of past arrears, to resolving the problems of unfunded liabilities, securitization of liabilities, and how past liabilities are assigned to the various successor companies, and so forth. These are all balance sheet matters that do not directly affect the choice of expansion strategy for the future (although failure to resolve them in a timely manner would affect the implementation strategy). This detail of financial engineering is in any event outside our terms of reference, and we have therefore simply adopted the assumptions of the Financial Restructuring Program on these matters.[19]

1.19 The economic analysis considers the economic flows, which are reconciled to the financial flows and summarized in the stakeholder analysis. The economic analysis calculates the conventional parameters of economic analysis (net present value (NPV) and economic rate of return (ERR) of the investment program, average incremental cost, long-run marginal cost (LRMC), and so forth). Finally, the various attributes (environmental, financial, economic) are displayed as trade-off curves and the efficient options identified. This whole sequence of calculations is embedded in a scenario and options analysis that permits easy sensitivity analysis and comparison of options.

1.20 A model for optimization of the capacity expansion plan then determines the least-cost configuration of generation for the planning horizon, given a reliability target (specified either as reserve margin or as a loss-of-load probability (LOLP)).[20] Based upon assumptions about fuel quality, such as the carbon, ash, and sulfur content, about heat rates, and about environmental controls (such as electrostatic precipitator (ESP) removal efficiencies), one then calculates the environmental residuals. To these are

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[19] The assumptions are taken from GoI (2001).

[20] In the Bihar and AP case studies, the ASPLAN model was used, with reliability constraints specified as an LOLP. The study of Haryana used the Enviroplan model, which optimizes the capacity expansion plan on the basis of minimization of the present value of system costs, based on an assumed cost of unserved energy. Enviroplan is used in this study of Karnataka.

added the emissions from self-generation. The tariff and government subsidy attributes are calculated in a simple financial model.

1.21 Section 2 provides a brief overview of the Karnataka power sector and the economic, financial, and environmental problems that it faces. Section 3 summarizes the main assumptions for the study.

1.22 The main scenarios are described in Section 4, followed in Section 5 by a discussion of the various options. The environmental impacts are presented and compared in Section 6. Section 7 presents a sensitivity analysis to assess the robustness of the conclusions with respect to the main uncertainties. The conclusions are summarized in Section 8.

2

The Karnataka Power Sector

Background

2.1 Although Karnataka's traditional entities the Karnataka Electricity Board (KEB) and Karnataka Power Company Ltd (KPCL) were among the better-performing Indian State Electricity Boards (and the first to have established a separate generation company, KPCL), over the past two decades strong growth in demand, led by relatively successful economic growth, declining real tariffs for domestic and agricultural consumers, and falling investment have led to increasing power shortages and the deteriorating financial condition of the sector. As described in a 1997 study by ICICI, in 1994–1995 Karnataka faced a 17 percent energy and 23 percent peak power demand shortfall, and in November 1995 50 percent cuts were imposed on high-tension (HT) industrial customers. These cuts increased to as much as 70 percent by March 1997. More and more industrial customers as a result installed captive generating plants. These plants in 1995–1996 had a capacity estimated at 2,015MW and accounted for 6.5 percent of total energy used by and 25 percent of sales to industrial customers. At this same time consumers in urban areas were facing frequent power cuts of six to eight hours of daily load shedding (ICICI 1997).

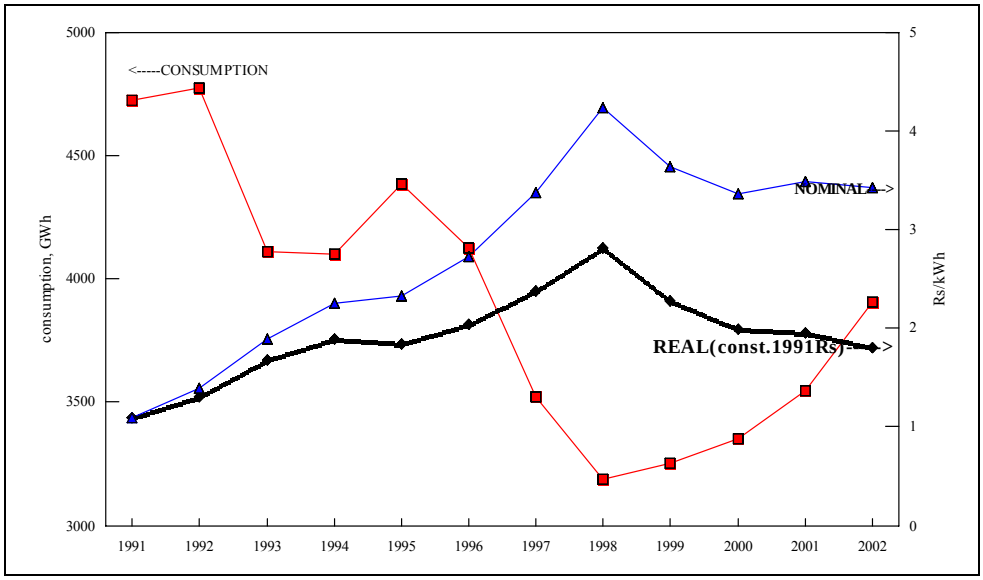
2.2 As shown in Figure 2.1, in the period 1991–1998 industrial HT tariffs increased sharply in both real and nominal terms, with the not unexpected result that HT industrial consumption declined, falling from 56 percent of the total to only 18 percent. Since 1998 the HT tariff has in real terms declined, and HT consumption increased.[21] This change was reinforced by a change in the diesel pricing policy of the Government of India. In the mid-1990s high-speed diesel oil (HSD) was subsidized at around Rs 11/liter; with the reduction of subsidies the price of HSD has risen to Rs 22/liter, which makes captive generation significantly more expensive than the grid. Over the longer term, the question is how much of the installed captive generation can be reclaimed by the grid once shortages are eliminated and the HT tariff declines to be more reflective of the true cost of service (which is obviously much lower than the economic cost of service for LT agriculture and domestic consumption).

2.3 Because the cost of HSD has increased sharply over the last few years (a consequence of GoI's change of policy to tie diesel prices to international prices), the

[21] Based on these data we have estimated the price-elasticity of demand for HT industrial energy consumption at –0.33.

resumption of robust industrial load growth may be expected. In addition, KPTCL has been offering a special Rs 3.25/kWh rate to consumers who replace diesel power by grid power. But while the present situation has improved (with only one-hour cuts, at worst), this resumed load growth may yet bring renewed power shortage in the near term.

Figure 2.1: Industrial Tariffs and Sales



2.4 In the early 1990s the GoK had high hopes that the private sector would provide much-needed generating capacity, but both of the large private power projects (the Mangalore coal project, sponsored by the U.S. firm Cogentrix,[22] and the 1,107MW Upper Krishna hydro project, sponsored by the Chamundi Power Company and promoted by a New Zealand-led consortium) came to naught (despite, in the case of the Cogentrix project, a signed PPA).[23] By late 1999 some 5,400MW of generating capacity had been approved by both bid and memorandum of understanding (MoU) routes, but the ability to bring any of these projects to financial closure in the absence of further federal counter guarantees[24] and with limited escrow capacity was increasingly doubtful.

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22 The original project design was for a 4 x 253.3MW plant, at a location some 35km north of Mangalore. The original sponsor Cogentrix withdrew from the project in 2000; current sponsors are China Light and Power of Hong Kong and Tata Electric Companies. This project is not included in the present capacity expansion plan (to 2010).

23 The Chamundi project encountered numerous problems, notably the inter-state water dispute between AP and Karnataka, the resolution of which by the Indian Supreme Court limited the operating height of the Almatti reservoir to 519.6 meters rather than the planned 524 meters, thus eliminating the power storage capacity that would have significantly increased dry-season power production and made possible a cascade of smaller run-of-river projects downstream.

24 The Cogentrix project was one of the original seven “fast track” projects that were assured of federal counter-guarantees.

2.5 A report by Crisil concluded that 1,500MW of escrow cover "may be manageable" but only with tariff rationalization and significant reduction of commercial losses at KEB (Crisil Advisory Services 1999). The subsequent Report of the High-Level Committee on Escrow (2000) concluded that escrows were not only unavailable, however, but were undesirable since they "jeopardize the proposed privatization of the distribution system." The report recommended that the GoK should "not provide escrow cover to any IPP." Not surprisingly, the capacity expansion plan approved by the GoK in 2001 as part of the restructuring plan includes only some 300MW of additional private power (the Tannerbhavi and Tata projects). In any event, the Report of the High-Level Committee strongly advocated as the first step the financial reform and restructuring of the sector; the thinking being that when financial health is restored and the sector is again fully creditworthy, the difficulties of adding IPP capacity will solve themselves.

The Reform Process

2.6 These problems were recognized by the GoK, and led in 1999 to the passage of the Karnataka Electricity Reform Act. Karnataka is now fully committed to the reform process and has commenced a program of reform and restructuring that includes the corporatization of the erstwhile Karnataka Electricity Board (KEB), establishment of a Regulatory Commission (KERC), unbundling of transmission and distribution, and the eventual privatization of electricity distribution in the state. Under the powers conferred by the 1999 act, two new entities have been incorporated as the successor entities of the KEB: the Karnataka Power Transmission Corporation Limited (KPTCL) and Visvesvaraya Vidyuth Migama Limited (VVNL). The financial restructuring plans were approved by Government Order in 2001. KPTCL has since been further divested of the distribution function by the creation of four distribution companies:

- Bangalore Energy Supply Company (BESCOM)
- Mangalore Energy Supply Company (MESCOM)
- Gulbarga Energy Supply Company (GESCOM)
- Hubli Energy Supply Company (HESCOM)

A consultant has been appointed by the GoK under the reform program to prepare the terms of privatization of the supply companies.

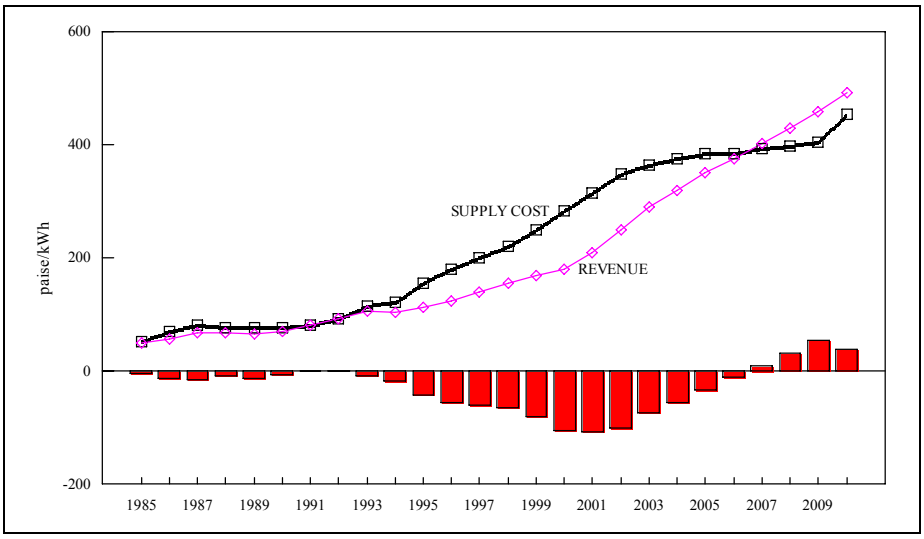
2.7 The objective of the financial restructuring and reform process is simply to reverse the trend of the past decade, which has seen the gap grow between the cost of supply and revenue realization. As shown in Figure 2.2, the GoK's 2001 plan foresees the gap closing in 2007.

Environmental Issues

2.8 Karnataka has no old, inefficient coal-fired plants that are not in compliance with environmental standards, and thus is not subject to the problems faced by electricity boards in states such as Haryana, Bihar, and Uttar Pradesh, which must bring old plants into compliance in the face of severe financial constraints. Karnataka's

one large fossil complex at Raichur is relatively modern and well run, and such environmental problems as may exist at this plant are relatively minor (MECON/Knight Piesold 2001).

Figure 2.2: Reversing the Trends



Air Pollution Impacts

2.9 The Mangalore Cogentrix project has highlighted the concerns about coal-based power generation on the west coast and the potential impact of air emissions (notably SO2) on the forests and biodiversity of the Western Ghats. Although these concerns were the ostensible basis for public interest litigation (that eventually was thrown out by the Supreme Court of India), the project in fact received all the necessary statutory environmental clearances.

2.10 The main air pollution concern of the power sector in Karnataka is unrelated to large coal units, existing or future, but rather is related to emissions from small self-generation units installed by consumers to mitigate the endemic power cuts. This is not necessarily apparent from simple calculations of gross pollutant emissions, but emerges only from damage cost assessments.

2.11 The differences between emissions from power plants with tall stacks in generally remote locations and those from ground-level sources in the centers of population (including urban vehicular emissions and self-generation) is highlighted in the World Bank Six Cities Study. As shown in Table 3.2, the damage costs of a ton of PM10 from a self-generation set is two orders of magnitude greater than that from a typical power plant. Given that the population of Bangalore is also one to two orders of magnitude greater than the affected populations in northern Karnataka (Raichur) or the west coast, the likely damage costs due to self-generation in urban Bangalore will be 1,000 times greater per kWh than those due to a coal plant at Mangalore. It is thus self-evident that one of the main environmental benefits of reform is the reduction of self-generation as supply shortages are eliminated.

Impact of Transmission Corridors Across the Western Ghats

2.12 The impact of transmission lines passing through the Western Ghats on biodiversity, forests, and wildlife is a major concern for the Mangalore coal projects. Such transmission connections to the major load center at Bangalore would be an essential part of any west coast project. Even should state-of-the-art pollution controls at the generating facilities minimize on-site and air emissions concerns (or should LNG be used as the fuel at west coast locations), the transmission line concerns would remain.

Power Projects in the Coastal Zone

2.13 Thermal power projects on Karnataka's west coast raise a number of potential concerns about appropriate use of the coastal zone. The relevant statute is the notification of the Ministry of Environment and Forests (MoEF) regarding use of the Coastal Regulation Zone (CRZ),[25] defined as the zone that extends 500 meters from the high tide line. Section 2.2 (iii) of the Regulation of Permitted Activities Requiring Clearance from MoEF permits the location of essential facilities within the coastal zone, as follows:

> Thermal power plants (only foreshore facilities for transport of raw materials, facilities for intake of cooling water and outfall for discharge of treated wastewater/cooling water).

2.14 While a coal-burning power plant cannot itself be sited in the 500 meter coastal zone, foreshore facilities are permitted, subject to their meeting the requirements for MoEF clearance. Construction in areas categorized as CRZ-I—that is, wildlife refuges, national parks, sanctuaries, reserve forests, and so forth—is prohibited. Areas already substantially developed (for example, provided with roads and drainage facilities) are not precluded under the notification from further development.

[25] 19 February 1991, as amended 3 October 2001.

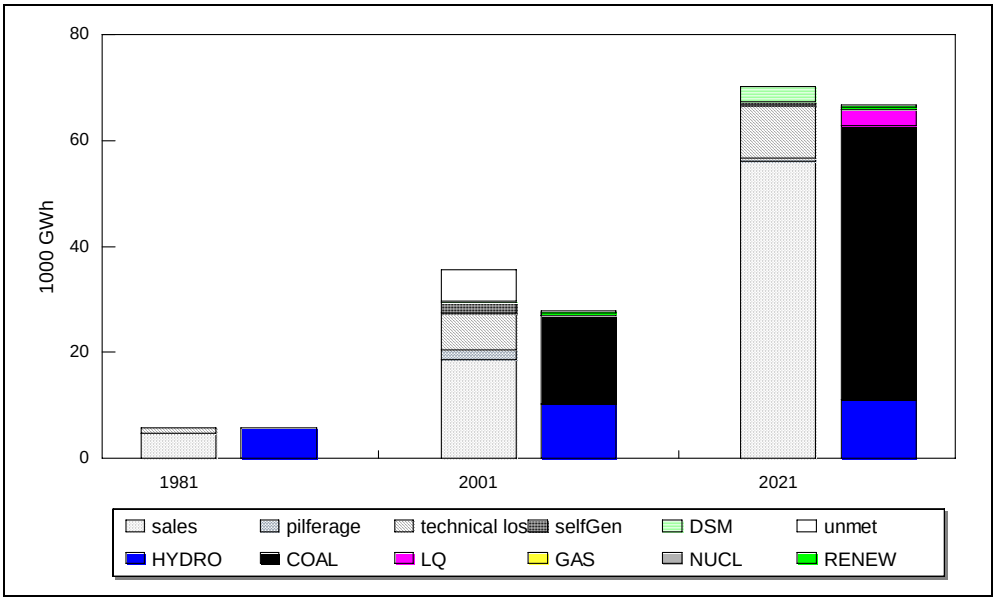
Consumptive Water Use

2.15 Karnataka's exposure to drought is significant, to the extent that it is classified as a drought state. The demand for consumptive surface water use for irrigation furthermore is steadily increasing: this is a major concern, given the disputes over water use in both the Krishna and Cauvery river basins. The GoK has given primacy in water allocation to irrigation, which raises the fundamental problem for power plant siting: if coastal sites are constrained by environmental concerns and inland sites by water use, how then is the state's need for additional base load power plants to be accommodated?

The Main Question

2.16 Figure 2.3 illustrates the dimensions of the long-term problem. In 1981, Karnataka's power supply was entirely hydro.[26] Today, hydro accounts for only about one-third of generation (since most of the central sector contributions are fossil-based). Power shortages have resulted in significant unmet demand; they also are responsible for the large amount of self-generation that exists.

Figure 2.3: The Long-Term Outlook



[26] Karnataka's first fossil unit at Raichur was commissioned in 1983.

2.17 The fundamental problem is simply this: if, as seems likely, further hydro additions are highly constrained, the bulk of the additional generation that must be added over the next 20 years must be some combination of fossil, renewables, and DSM (which in a business-as-usual environment would most likely be coal). A significant proportion of this coal capacity may be located in other states, such as Orissa or Tamil Nadu, but the environmental effects associated with such projects should be counted to Karnataka's account (or may be recovered by the exporting state through higher royalties). The extent to which there are realistic alternatives to a coal-based future, and the environmental implications that follow, are the issues discussed in this report.

3

Assumptions

Issues in Economic Analysis

Interest During Construction

3.1 Interest during construction (IDC) is a transfer payment.[27] Notwithstanding its appearance in many generation planning studies (which are prepared mostly by engineering firms),[28] IDC has no place in economic analysis, for all capital is priced at the assumed opportunity cost of capital, without regard to what is debt and what is equity. If in fact the financial cost of debt is different to the assumed opportunity cost, then in the reconciliation of economic and financial flows the difference is accounted as a transfer payment to or from lenders.

3.2 The inclusion of IDC would be incorrect even in the case of a foreign-financed private sector project. The economic costs of such a project should be captured as the flows of repatriated equity returns and debt service payments when they arise (or converted to a single NPV at the discount rate). In other words, the economic capital cost of a privately financed foreign IPP is the NPV of the actual equity and debt service payments, not the "capital cost" claimed by the IPP (which is frequently overstated).

Economic Cost of Coal

3.3 The economic cost of coal is a key factor. The approach taken in the EIPS case studies of Bihar, Andhra Pradesh, and Haryana is that the economic price of coal, expressed as rupees or dollars per unit of heat at any given mine location in India, is the border price of imported coal adjusted for (economic) domestic transportation costs.

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[27] See, for example, *Handbook on Economic Analysis of Investment Operations* (World Bank 1996), which states with respect to interest during construction:

> *Sometimes lending institutions capitalize the interest during construction … whether the interest is capitalized or not, its treatment for purposes of economic analysis is the same: interest during construction is still a transfer and is omitted from the economic accounts.*

[28] For example, the Ewbank Preece generation capacity expansion planning exercise of 1995 for Uttar Pradesh uses a figure of 9 percent for IDC, as opposed to 12 percent for the discount rate—the difference being justified by what is claimed (incorrectly) to be "CEA's practice." Even if it were the same, inclusion of IDC is still incorrect (Ewbank Preece, 1996)

3.4 Although it is sometimes argued that a more appropriate measure would be the long-run marginal cost (LRMC) of domestic coal production, there is in fact no inconsistency. If LRMC is lower than the netback based on border price, then the difference is accounted as a resource rent. If the economic LRMC (or the financial FOB (free on board) cost) is higher than the netback value, the difference is accounted as a subsidy.

Benefits

3.5 The usual power sector planning approach requires the optimization of the capacity expansion plan for some given load forecast—that is, determination of the least-cost plan to meet the demand. This ensures an economically efficient plan without any express consideration of benefits: if the benefits of electricity consumption are constant, then the economic optimum necessarily follows from the minimization of costs to supply that consumption. Different scenarios can be validly compared with each other given a constant level of benefits.

3.6 When different scenarios provide for different levels of consumption, however, they can no longer be compared without express adjustment for the different level of benefits provided. For example, in a "no reform" scenario financial constraints on additional generating capacity may result in a given level of shortages. These shortages are either accommodated by self-generation capability or they are unfulfilled, representing a real loss of economic benefits. The total costs of electricity supply to meet some given demand must therefore include the costs of self-generation and the cost of lost benefits where shortages are not met by self-generation. The benefit of electricity consumption is captured by willingness-to-pay (in this case, the area under the demand curve of the foregone consumption), the minimum value of which is the tariff that the consumer would pay were the electricity available. However, actual WTP for the first tranches of consumption (and hence average WTP for the entire consumption) is likely to be significantly higher (as evidenced by the high costs of battery charging/rectifier sets used by domestic households).

3.7 This study uses maximization of the PV of net economic benefits, rather than minimization of system cost, as the economic attribute. This has several important advantages, including primarily the following:

- Explicit recognition of the benefit stream makes the analysis consistent in format with conventional benefit–cost analysis (BCA). This permits, for example, the direct calculation of the economic rate of return (ERR) of the investment program associated with each option.
- It provides for easier reconciliation of the financial and economic flows, and permits a ready distributional analysis (identification of the beneficiaries).

Environmental Damage Costs

3.8 Many recent power sector studies conducted for the World Bank, including economic project appraisals as well as sector work, have monetized damage costs from local air emissions.[29] This study of Karnataka uses the "Six Cities Study," prepared by the World Bank's Environment Department (Lvovsky and others 2000), as the basis for the damage cost estimates. The Six Cities study (of Mumbai, Shanghai, Bangkok, Krakow, Santiago, and Manila) derived representative damage cost estimates for power plant emissions of PM10, SO_2, and NOx. The marginal damage cost estimates, by type of source, are shown in Table 3.1.

Table 3.1: Marginal Damage Costs (US$/Ton)

	Power Plant (High stack)	Large Industry (medium stack)	Self-Generation (near ground level)	Ratio (self-generation: power plant generation)
Mumbai				
PM10	234	1,077	7,963	34:1
SO_2	51	236	1,747	34:1
NO_x	20	93	668	33:1
Shanghai				
PM10	161	502	5,828	36:1
SO_2	36	112	1,295	36:1
NO_x	11	33	385	35:1
Manila				
PM10	345	1,828	17,942	52:1
SO_2	61	324	3,183	52:1
NO_x	24	129	1,265	52:1
Bangkok				
PM10	828	2,357	28,722	34:1
SO_2	147	417	5,087	34:1
NO_x	57	162	1,971	34:1
Krakow				
PM10	97	682	13,255	136:1
SO_2	18	130	2,522	140:1
NO_x	4	29	560	140:1
Santiago				
PM10	692	4,783	88,551	128:1
SO_2	132	911	16,864	127:1
NO_x	35	240	4,445	127:1

Source: *Lvovsky and Others (2000)*

3.9 Mindful of the cautions emphasized by the authors of the Six Cities study, the indicative marginal unit values shown in Table 3.2 may be used.

[29] For example, all of the World Bank power sector project appraisals for China since 1995 have used the benefit-transfer method to estimate damage costs for TSP, SO_x, and NO_x, and included these values in the power system planning studies to identify social least cost expansion plans.

Table 3.2: Unit Health Damages (US$/Ton per 1,000,000 Population per US$1,000 of Per Capita Income)

1 ton change in emission of:	High Stack (power plants)	Medium Stack (large industry)	Low Stack (self-generation)
PM10			
range for six cities	20–54	63–348	736–6,435
average	42	214	3,114
SO_2			
range for six cities	3–8	10–56	121–1,037
average	6	33	487
NO_x			
range for six cities	1–3	3–13	29–236
average	2	9	123

Source: *Lvovsky and others (2000)*

3.10 The result that is of greatest significance is that unit health damages from self-generation plants (domestic, commercial, and small industry plants that fall into the category "low stack") are two orders of magnitude greater than the damages from power plants. This is because emissions from such self-generators are typically at or near ground level and in close proximity to population centers, in contrast to those from the generally more remote power plants equipped with high stacks. In the context of Karnataka, it is clear that 1 ton of emissions from the coal-fired Raichur plant (in the far north) or coal-based plants on the coast would have a significantly lower damage cost than the same 1 ton emitted from self-generation plants in Bangalore. It follows that the total emissions of such pollutants is less important than the fact of the location in which these emissions occur.

3.11 Damages from water pollution have not been monetized in this study, in large part because of the absence of relevant monetization studies upon which to draw. Some Indian damage cost studies do cover water pollution, but these relate exclusively to industrial sources, agricultural run-off (such as pesticide residues), and inadequate municipal wastewater treatment.[30] For power plants, studies suggest that damages from local air pollutants outweigh those associated with water discharges by at least two orders of magnitude.[31] Certainly in the case of India, where all new fossil plants in inland regions require evaporative cooling towers, the water issue is not so much that of the

[30] See, for example, Appasamy and others (2000) and Brandon and Hommann (1995). Brandon and Hommann found that industrial water pollution was the single most important source of health damages, responsible for US$5.7 billion out of a total of US$9.7 billion per year—about 4.5 percent of GDP at 1992 values.

[31] See, for example, the "Extern-E" studies prepared for all of the countries of the EU, which examined all environmental externalities associated with the entire fuel cycle of different technologies. These studies found the human health impacts associated with air pollution to account for more than 98 percent of the total externality costs (excluding those associated with GHG emissions). Mortality and morbidity are by far the largest component of the damage costs for air pollutants. For example, in the French Extern-E analysis of the coal fuel cycle (Spandaro and Rabl, 1998), total damage costs were estimated at €0.4924/kWh. Costs associated with mortality and morbidity (€0.484/kWh) dominated this value, with crop damage and materials damage rated at only €0.0072/kWh and €0.0012/kWh, respectively.

treatment of blowdown and wastewater streams as much as it is consumptive use. This finding is of obvious importance to Karnataka given the inter-state water disputes that are associated with its major river basins.

Global Externalities

3.12 The global damage costs due to greenhouse gas (GHG) emissions are potentially very high, and have been debated at length by the Intergovernmental Panel on Climate Change (IPCC). The 1995 IPCC Working Group III report estimated these costs to be in the range of US$5–125/ton carbon,[32] and these figures form the basis for most of the comprehensive valuation studies of damage costs from electricity generation. For example, the Extern-E project, a study by the European Union of the externality costs in all EU countries, used a range of US$14–37/ton CO_2, or US$51–135/ton carbon).[33]

3.13 A second approach is to use a value that is based on the likely global willingness-to-pay for carbon avoidance, for which the expectations of the Prototype Carbon Fund (PCF) may be used. The PCF has set US$20/ton as the target price outcome averaged across the PCF portfolio at the end of carbon purchase agreements entered into; the present emissions reduction cost screening criterion for PCF eligibility is US$10/ton carbon (PCF 2002).

3.14 For the baseline calculations we use the second approach, with an average value of US$15/ton carbon. This can be taken as representative of an average price at which renewable energy developers may sell their carbon offsets, and is of immediate relevance to the negotiations between the transmission companies and the developers over revisions to the tariff (see Section 5). The potential implications of using damage costs rather than emission reduction costs are presented in the sensitivity analysis of Section 7.

Environmental Costs versus Environmental Externalities

3.15 How to define environmental costs and how to account for them is a crucial issue. A thermal power plant has a potentially large number of environmental and social impacts, many of which are required to be mitigated to some level by environmental regulation, others of which are mitigated by the intrinsic developments of technology. For example, flue gas desulfurization at a coal plant can be avoided by a range of options: by burning lower-sulfur coal; by blending the primary fuel with very-low-sulfur coal (as is being contemplated for the 660MW Vijayawada extension in AP);

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[32] One of the main decisions to be made when calculating a single marginal damage cost value is the choice of discount rate (since damages arising from present emissions will occur many years from now). For example, the Extern-E study shows that a baseline rate of US$170/ton carbon using a 1 percent discount rate falls to US$60/ton using a 3 percent discount rate. There are further issues regarding the form of the damage cost function itself (linear versus nonlinear) and the problems inherent in using a single value when damage costs (whatever they may be) vary by orders of magnitude from country to country, depending on their geography, population, income, economic structure, and land use. We are not aware of a rigorous study of potential climate change damage costs in Karnataka.

[33] See, for example, Spandaro and Rabl (1998).

or by adopting fluidized bed combustion, in which limestone is injected into the combustion chamber and SO_2 is removed by the formation of gypsum (as is used in Gujarat and as is being proposed for lignite plants in Rajasthan).

3.16 This study does not separately track the costs of pollution mitigation, but rather assumes that all new projects include in their capital costs such environmental controls as may be required to meet current Indian standards. Thus the capital costs of thermal projects include electrostatic precipitators (ESPs) to bring particulate emissions to the required levels.

3.17 Further critical questions are the extents to which environmental damage costs are internalized (that is, reflected in the cost of building and constructing new plant) and to which these costs must be accounted for as externalities. Table 3.3 lists some of the environmental impacts of a power plant, and how they are accounted for in this study.

3.18 The distinction to be made is between that which can be internalized and that which can remain as an externality. For example, our estimate of the damage to agricultural productivity caused by air pollution is included in our air emission damage cost. The loss of agricultural production on land converted to power station use (for example, for the land areas needed for ash disposal) is internalized in the capital and operations and maintenance (O&M) cost of the project.

3.19 This study does not in any event replace the need for detailed environmental impact assessments at the time of project development, much less substitute for the required statutory clearances. When we speak of a general siting option for thermal projects on the west coast it is understood that such plants cannot be located where their foreshore facilities would fall in ecologically or environmentally sensitive areas classified CRZ-I. The only sites that may be considered are those at which MoEF clearance is possible and where the actual power plant could be viably sited outside the 500 meter coastal zone.

Fuel Price Assumptions

3.20 Past EIPS analyses used the economic prices derived in a 1997 study by the Tata Energy Research Institute (TERI 1997). The values of that study now require updating. One of the limitations of the study furthermore was the lack of a consistent framework for forecasting the relative international prices of coal, oil, and liquefied natural gas (LNG), linked to a single marker. These relationships experience their own temporary market fluctuations, but for a long-range planning study, as is presented here, a consistent framework is essential. Experience shows that even when prolonged perturbations from long-term averages occur, they generally presage a future market adjustment, and one that may be quite sudden.

Table 3.3: Accounting for Environmental Costs

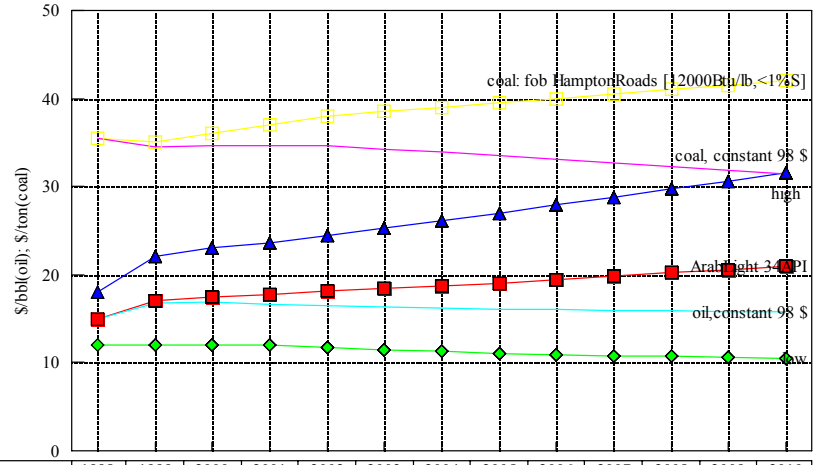
Environmental impact	How quantified in this study	Issues
Relocation and resettlement	Internalized in capital costs	While project-affected families may be compensated for their economic losses by the compensation package provided by the government, there may be some residual loss of amenity that cannot be internalized (for example, the value that individuals may give to living on ancestral lands)
Cost of crop losses at land converted to power station use	Internalized in capital costs	The market value of land in private ownership reflects the stream of future earnings from the productive use of that land. There may, however, be issues where land is owned by the state
Land degradation	Internalized in capital and operating costs	Operation and maintenance costs include provision for land reclamation after ash ponds are filled, and for the restoration of vegetation cover
Water pollution	Internalized in capital and operating costs	Capital costs include allowances for lined ash ponds where there is a risk of groundwater pollution
Cost of property and crop damage from air pollution	Externality, included in our estimates of environmental damage costs	
Health impacts from air pollution	Externality, included in our estimates of environmental damage costs	See details as discussed above
Loss of biodiversity	Not quantified	Lack of quantification is a major limitation of this study [a]

[a] Methods have been proposed to develop a quantitative biodiversity index, but these have yet to come into general use and the level of detailed information that is required lies outside the scope of this report. The only example in the (South Asian) literature is that of Meier and Munasinghe (1994), which derived a biodiversity index, based on the probability of encountering an endemic species in a habitat affected by a power project, in a multi-attribute analysis of Sri Lanka. This required a significant data collection effort on land use at all potential sites in the country.

World Oil Price

3.21 The approach taken in this study is to link all prices to that of the world oil price, with Brent as the marker crude, on the recommendation of a study of Asian oil markets (Horsnell 1997). Forecasting future oil prices is a hazardous business, particularly over short time frames: for example, the World Bank's 1998 world oil price forecast (used in the previous EIPS studies) appears to have significantly underestimated oil prices over the short term (see Figure 3.1). The low and high forecasts represent the 70 percent probability bounds, yet the US$24–32/bbl price of oil in 2002 lies well outside the Bank's range of US$11–25.5/bbl.

Figure 3.1: 1998 World Bank Oil Price Projection



	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
ArabLight 34API	15	17	17.5	17.8	18.1	18.4	18.7	19	19.4	19.8	20.2	20.6	21
low	12	12.0	12.0	12.0	11.8	11.5	11.3	11.0	10.9	10.8	10.7	10.6	10.5
high	18	22.0	23.0	23.6	24.5	25.3	26.2	27.0	27.9	28.8	29.7	30.6	31.5
coal	35.5	35.0	36.0	37.0	38.0	38.5	39.0	39.5	40.0	40.5	41.0	41.5	42.0
coal, 1998 $	35.5	34.5	34.6	34.6	34.7	34.3	33.9	33.5	33.1	32.7	32.3	31.9	31.5
oil, 1998 $	15.0	16.8	16.8	16.7	16.5	16.4	16.2	16.1	16.0	16.0	15.9	15.8	15.7

3.22 The present oil price volatility is largely influenced by short-term factors, however, such as the labor unrest in Venezuela and the war in Iraq, and these presumably will be resolved over time. Over the longer term it is reasonable to expect that prices will trend back toward the marginal cost of production, and recent forecasts suggest a long-term equilibrium price of US$20–25/bbl. The 2001 World Bank forecast, for example, sees a US$19.5/bbl price for 2010 (World Bank 2002).

3.23 The consequences of the power sector's exposure to short-term fossil price volatility nonetheless constitute a separate policy issue that is of particular relevance to the renewable energy and DSM alternatives. Fossil fuel price volatility can be hedged by futures and swaps, but this comes at a cost—and one that may be avoided by renewable energy and DSM options.[34]

Coal Prices

3.24 Although coal prices do not exhibit the volatility of world oil prices, the longer-term averages show remarkable correlation. Figure 3.2 compares the annual average Brent and coal (FOB New South Wales) prices for the period 1981–2000.[35]

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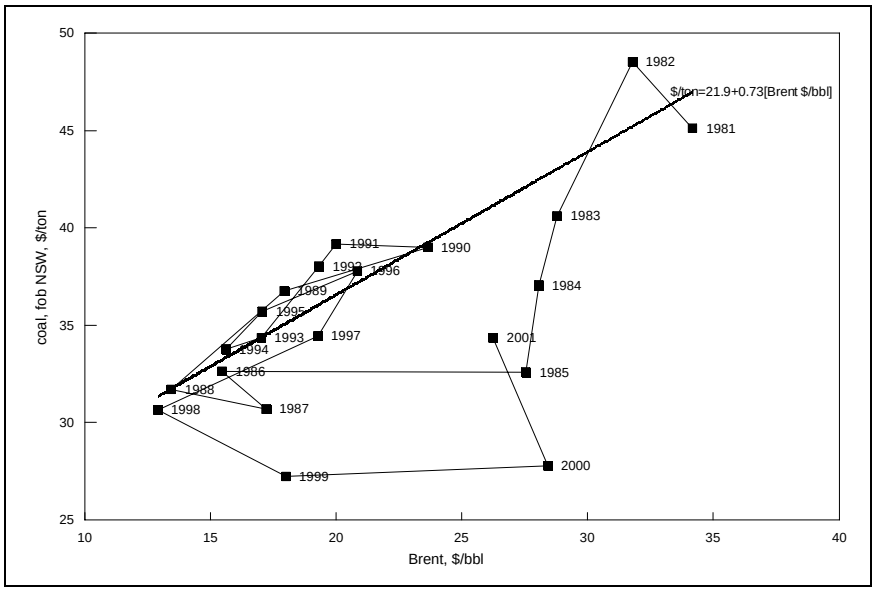
[34] The extent to which renewable energy generation options serves as a cost-effective hedge against uncertainty is the subject of an ongoing study by the Energy and Water Department of the World Bank.

[35] The trend line used for modeling purposes (bold line in the figure) is estimated as *Coal[FOB NSW, US$/ton]=21.9+0.73[Brent, US$/bbl]*; R^2=0.854. This trend line (estimated by ordinary least squares) excludes the years 1984-1985, and 1999-2001, for reasons discussed in the text. If these years are included, the relationship changes to *coal=25.29+0.47[Brent]*, with a significantly reduced R^2 of 0.33.

Figure 3.2: Australian Export Coal and Brent Oil Prices



3.25 There have been two periods over the last 21 years when the general relationship between coal and oil prices has shown a significant deviation (Figure 3.1). The first was in the years 1983–1985, prior to the oil price collapse of 1986: this period was characterized by an artificially high crude oil price as OPEC tried to defend its posted pricing system for crude oil, despite falling product prices. This effort was not sustainable, leading to the spectacular fall in crude prices in late 1986.

3.26 The second period of price aberration has been the past few years, when coal prices in the Asia-Pacific markets have been significantly below their normal values. This was a consequence of the aftermath of the financial crisis of 1997–1998 and the rapid growth of China's coal exports, which depressed prices. Coal prices recovered somewhat in 2001 relative to the price of oil, but collapsed again in 2002 (Australian export coal spot prices falling to as little as US$22/ton) before recovering in late 2002 to more than US$30/ton.

3.27 To derive the Indian border price requires that assumptions be made about ocean freight charges from the major export ports. These are taken from a recent Australian study (see Table 3.4) (Connell Wagner Pty Ltd 2001). Note that the difference in freight charges for vessels of different size (e.g. US$1.50/ton between Capesize and Panamax from NSW to Madras) is greater than the incremental difference in distance (US$0.70 between Madras and Mangalore for the extra 500 nautical miles from NSW in Capesize vessels).

Table 3.4: Ocean Freight Costs to India

Discharge port	Units	Loading port				
		Indonesia (Tanjung Bara)	Australia (Newcastle, NSW)	Australia (Gladstone)	S. Africa (Richards Bay)	China (Qinhuang dao)
East Coast India						
Distance to Madras	Nautical miles	2,700	5,500	5,000	4,100	4,300
Handymax	US$/ton	9.50	16.50	15.75	13.25	14.00
Panamax	US$/ton	7.50	12.50	11.25	10.00	10.50
Capesize	US$/ton	7.25	11.00	10.50	8.50	
West Coast India						
Distance to Mangalore	Nautical miles	3,200	5,700	5,200	3,700	4,800
Handymax	US$/ton	10.50	17.00	16.25	11.90	15.50
Panamax	US$/ton	8.50	13.00	12.60	8.80	11.00
Capesize	US$/ton	8.00	11.70	11.10	7.40	

Source: Connell Wagner Pty Ltd (2001)

3.28 Care is required when converting prices of internationally traded coals to that of Indian coal, because the latter is priced on the basis of Useful Heat Value (UHV), an attribute unique to India and which is quite different from the conventional measure of gross calorific value (GCV).[36] For example, a coal with a UHV of 3,200 kCal/kg (typical F grade) may have a conventional GCV of 4,300 kCal/kg. The potential sources for Raichur are the Mahanadi coalfields in Orissa, the Western coalfields in Madhya Pradesh, and the Singareni collieries in Andhra Pradesh. The posted price structure of these sources is given in Table 3.5. Pithead prices vary considerably, with Singareni the most costly. Raichur purchases D grade coal from Singareni and E grade coal from the Western coalfields.

[36] The formula for useful heat value (UHV), in kCal/kg, is:

$$UHV=8900-138\ (A+M)$$

Where *A* is the ash content as a percentage and *M* is the moisture content, also as a percentage.

The formula in general use in India to calculate GCV (as kCal/kg) is:

$$GCV= 8555.5 - 145.55M – 94.11A$$

This gives values that are very close to conventional characterization as LHV. However some companies (for example, APGENCO) use the alternative formula:

$$GCV=33820\ C –143050\ (H-O/8)+9304\ S$$

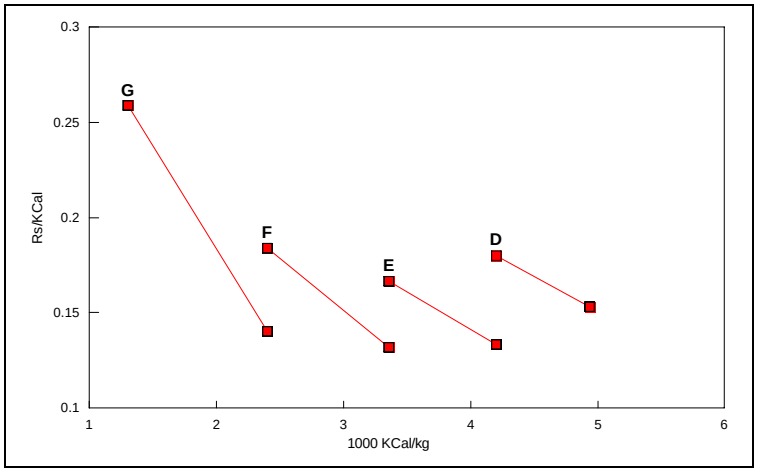
Where O is the oxygen content, H is the hydrogen content, C is the carbon content, and S is the sulfur content. GCV is expressed in kJ/kg.

Table 3.5: Coal Prices (in Rs/Ton, Effective 18 August 2002)

Grade	UHV (kCal/kg)	Western coalfields	Singareni	Mahanadi coalfields
D	4,200–4,940	956	1028	566
E	3,360–4,200	743	823	445
F	2,400–3,360	620	694	351
G	1,300–2,400	467	524	250

3.29 Under this system the cost of coal within any grade can vary greatly; for example, in the F grade by 40 percent per kilocalorie (from Rs 0.13/kCal to Rs 0.18/kCal). This gives rise to a bizarre relationship between the cost in Rs/kCal and the UHV in kCal/kg (see Figure 3.3). Suppliers clearly have a great incentive to supply coal at (or near) the lower end of the UHV band for each grade. The system has no parallel in international practice and cannot possibly survive market reforms.

Figure 3.3: Price versus Heat Content (UHV)



3.30 Table 3.6 shows a comparison of the costs of imported Australian and domestic (Talcher) coal at Madras and Mangalore, based on an exchange rate of US$1:Rs 48 and a coal price, FOB New South Wales (NSW), of US$30/ton. The assumption is that the Talcher coal would be sent by rail to Paradeep, and thence transported by coastal ships. At Madras, the economic price of imported coal is Rs 0.316/MCal, compared to Rs 0.367/MCal for domestic coal from Talcher. The customs duty imposed at Madras raises the price of Australian coal to Rs 0.408/MCal, however, making it more costly than the domestic alternative. In contrast, the imported coal at Mangalore, priced at Rs 0.414/MCal, is slightly cheaper than Talcher coal (Rs 0.426/MCal).

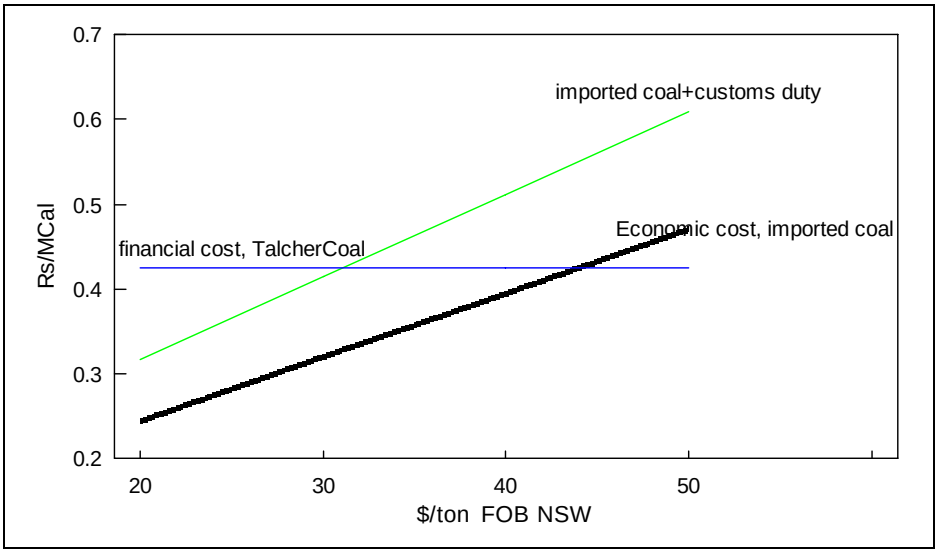
Table 3.6: Imported versus Domestic Coal Prices at Madras and Mangalore

		Location		Assumptions/ Data source
		Mangalore	Madras	
Imported Australian coal				
Calorific value	kCal/kg	6500	6,500	[Connell Wagner]
Exchange rate	Rs/US$	48.00	48	
FOB NSW	[US$/ton]	30.00	30	
Freight from NSW	US$/ton	11.70	11	[Connell Wagner]
CIF	US$/ton	41.70	41.00	[Connell Wagner]
Handling	US$/ton	1.00	1.00	[Connell Wagner]
Economic cost	US$/ton	42.70	42.00	
	Rs/ton	2,050	2,016	
	Rs/MCal	0.315	0.310	
Pilferage and losses		0.02	0.02	[Connell Wagner]
Adjusted economic cost	Rs/MCal	0.322	0.316	
Customs duty [CIF]	[ ]	29.5 percent	0.295	
	Rs/ton	590	581	
Financial cost	Rs/ton	2,640	2,597	
Adjusted financial cost	Rs/MCal	0.414	0.408	
Talcher Coal				
Talcher coal, FOB Mine	Rs/ton	511	511	
Rail to Paradeep	km	200	200	[Connell Wagner]
	Rs/ton	233	233	TERI (=135 + 0.487 [dist])
		297	297	[TERI updated to 2001]
Port charges	Rs/ton	300	300	[TERI updated to 2001]
Distance from Paradeep	km	3,350	1,056	[Connell Wagner]
Variable	Rs/km/ton	0.11	0.11	regression model, TERI data
Fixed	Rs/ton	344	344	regression model, TERI data
Total	Rs/ton	712.5	460.16	
CIF	Rs/ton	1,821	1,568	
Calorific value	kCal/kg	4,500	4,500	
Cost	Rs/MCal	0.405	0.349	
Pilferage and losses		0.05	0.05	[Connell Wagner],[TERI]
Adjusted cost	Rs/MCal	0.426	0.367	

Sources: *TERI 1997; Connell Wagner Pty Ltd (2001)*

3.31 It is doubtless for this reason that the GoI, in an effort to protect Coal India, increased the rate of customs duty from 10 percent on CIF (the cost, insurance, and freight value) in 1998 to 20 percent in 1999 and to 35 percent in May 2000. In March 2001 the duty was reduced to 29.5 percent. Figure 3.4 shows that the current rate of customs duty provides protection (at Mangalore) against Australian coal priced at US$30/ton or greater, FOB NSW. During the depressed spot market conditions of 2002, when the FOB price fell below US$30/ton, even the 29.5 percent customs duty did not provide protection (at Karnataka west coast locations).

Figure 3.4: Customs Protection for Domestic Coal



3.32 The netback economic price of coal at Talcher calculates as shown in Table 3.7 to Rs 974/ton, calculated as the netback of Australian coal delivered to Paradeep (and adjusted for the differences in calorific value).

Table 3.7: Economic Cost of Coal at Talcher [as Netback]

FOB NSW	[US$/ton]	30	
Freight NSW to Paradeep	[US$/ton]	11	[Connell Wagner]
Paradeep landed cost	[US$/ton]	41	
	[Rs/ton]	1,968	
Port fees	[Rs/ton]	-300	[TERI]
Rail to Paradeep	[Rs/ton]	-233	[TERI]
Netback at Talcher	[Rs/ton]	1,435	
Pilferage and losses	[Rs/ton]	1,406	
Adjustment for calorific value	[ ]	0.692	
Talcher netback price	[Rs/ton]	974	

3.33 Given this economic price for Talcher coal of Rs 974/ton, the economic cost of domestic coal at south Indian locations, absent customs protection, is significantly higher (see Table 3.8). From this we can conclude that the economic least-cost option for coal generation on the west coast of Karnataka is imported coal. From a national economic perspective, Talcher coal should be used in such locations where its economic cost is lower than that of imported coal—that is, inland to the northern regions of India. Any attempt by the GoI to provide customs protection for coal shipped to coastal south India would be economically inefficient: in effect, it would simply impose additional costs on electricity generation in the southern states as a subsidy to uncompetitive mines in the coal-producing states.

Table 3.8: Domestic Coal in South India at Economic Prices

		Location		Assumptions/ Data source
		Mangalore	Madras	
Talcher coal, FOB Mine	Rs/ton	974	974	
Rail to Paradeep	km	200	200	[Connell Wagner]
	Rs/ton	233	233	TERI (=135 + 0.487 [dist])
		297	297	[TERI updated to 2001]
Port charges	Rs/ton	300	300	[TERI updated to 2001]
Distance from Paradeep	km	3,350	1,056	[Connell Wagner]
Variable	Rs/km/ton	0.11	0.11	regression model, TERI data
Fixed	Rs/ton	344	344	regression model, TERI data
Total	Rs/ton	712.5	460.16	
CIF	Rs/ton	2283	2031	
Calorific value	kCal/kg	4,500	4,500	
Cost	Rs/MCal	0.507	0.451	
Pilferage and losses		0.05	0.05	[Connell Wagner],[TERI]
adjusted cost	Rs/MCal	0.534	0.475	
Australian coal (Table 3.3)	Rs/MCal	0.414	0.408	

3.34 Table 3.9 shows the price structure for coal delivered to Raichur from Singareni, and Table 3.10 for coal from Western coalfields.

Table 3.9: Financial Price of Coal to Raichur from Singareni

	D grade	E grade	F grade	G grade
Price	1,028.00	823	694	524
Royalty	90.00	90	90	90
Stowing excise duty	3.50	3.5	3.5	3.5
Surface transport	35.00	35	35	35
Total	1,156.50	951.50	822.50	652.50
CST@4 percent	46.26	38.06	32.90	26.10
Total ex-Mine	1,202.76	989.56	855.40	678.60
Distance (km)	525			
Freight	415.90			
Delivered cost at Raichur	1,618.66	1,405.46	1,271.3	1,094.5
Of which total taxes and royalties	139.76	131.56	126.4	119.6
	8.63 percent	9.36 percent	9.94 percent	10.93 percent

Table 3.10: Financial Price of Coal to Raichur from Western Coalfields

	D grade	E grade	F grade	G grade
Price	956	743	620	467
Processing	20.00	20.00	20.00	20.00
Royalty	85.00	85.00	65.00	65.00
Excise duty	3.50	3.50	3.50	3.50
Surface transport	30.00	30.00	30.00	30
Total	1,094.50	881.50	738.50	585.50
CST@4 percent	43.78	35.26	29.54	23.42
Total ex-Mine	1,138.28	916.76	768.04	608.92
Distance (km)	661	661	661	661
Freight	516	516	516	516
Delivered cost at Raichur	1,654.28	1,432.76	1,284.04	1,124.92
Of which total taxes and royalties	132.28	123.76	98.04	91.92
	8.00 percent	8.64 percent	7.64 percent	8.17 percent

Petroleum Product Prices

3.35 To project petroleum product prices we apply the product price to crude price ratios derived by TERI (TERI 1997). The ratios are 130 percent of the crude price for naphtha; 66 percent for heavy fuel oil; and 135 percent for high-speed diesel oil (HSD).

3.36 The fuel outlook in southern India changed dramatically in 2002 with the announcement by a consortium headed by Reliance Industries of a major gas find in Andhra Pradesh. The find, in the Krishna–Godaveri Basin in the Bay of Bengal, was one of the world's largest of 2002, and has over the next few years the potential of doubling India's gas output. However, the finds are in water 1,000 meters deep about 48 kilometers offshore—while American companies have produced gas in even deeper waters in the Gulf of Mexico, India lacks a comparable support network of production companies. To develop these fields will cost between US$500 million and US$1 billion, plus the costs of pipeline development. The first planned pipeline reportedly will run from the terminal at Kakinada through AP, Karnataka, Goa, and Maharashtra.[37]

3.37 This study assumes three gas-based options for Karnataka. The first is LNG-based, with locations on the west coast using combined-cycle combustion turbine (CCCT) technology.[38] The second is the use of simple-cycle combustion turbines in the Bangalore area (assuming that a branch of the pipeline would reach Bangalore by 2010).

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[37] This gas find makes the prospects for the much-discussed gas pipelines from Bangladesh, Iran, and the Central Asian republics, all of which are fraught with geopolitical problems, even less likely.

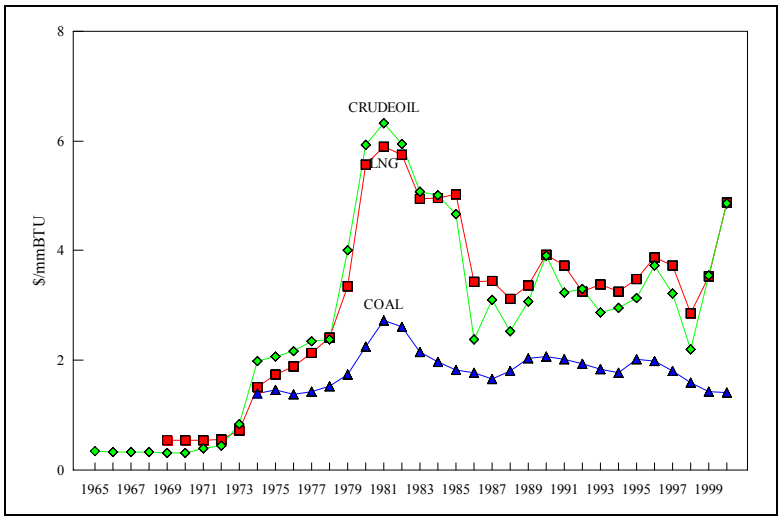
[38] Even if land pipelines from Bangladesh or Turkmenistan were to become a reality, the proposition is fanciful that the producing countries would export gas at prices substantially lower than the world market price (on a delivered Btu basis). Where actual production costs are lower than the netback values based on international prices, these countries will certainly capture the implied resource rents themselves.

This option for peaking power has two attractions: it avoids the need for transmission lines across the Western Ghats, and it avoids the water requirements of steam-cycle generation. The third is a CCCT-based/intermediate load operation, with a consumptive water use of 1.45 liters/kWh/kWh, located in the Krishna Basin in northern Karnataka.

3.38 Historically, LNG prices in the region have been benchmarked against those for Japan, the largest LNG importer in the Asia-Pacific region. These prices are in turn tied to crude oil prices (of the "Japan Crude Cocktail," or JCC), with short-term volatility smoothed out. The average annual LNG price for long-term planning studies can reasonably be projected as tied directly to the average annual crude oil marker price (see Figure 3.5).[39]

3.39 The traditional pricing arrangements are undergoing change, however. LNG already commands lower prices in the more competitive European market, and the traditional long-term contract arrangements for LNG shipments to Japan and Korea, based on the JCC, are gradually being supplemented by greater reliance on spot and short-term arrangements.

Figure 3.5: Japanese LNG Prices versus Prices of Crude Oil and Coal



3.40 The GoI intention is to index domestic gas prices to a basket of fuel oils. The resulting prices, under various assumptions made of the world oil price, are shown in Table 3.11. The existing gas price is highly subsidized.

[39] For details of LNG price formation, see Fujime (2002). The so-called "Asia" premium of about US$1/bbl (for both oil and LNG) is attributed to long-term contracts linked to average Dubai and Oman prices. In addition, higher LNG prices have been paid because of the linkage to crude oil, rather than burner-tip prices with immediate substitutes. Thus LNG prices have been as much as US$1/MBtu higher than those paid by U.S. and European LNG consumers. The average 2000 CIF price of LNG imported into the United States was US$3.18/MBtu, compared to $4.88/MBtu in Japan.

Table 3.11: Natural Gas Prices (Exchange Rate of Rs 48 : US$1)

		Current gas price	Deregulated pricing				LNG
Crude price	US$/bbl		16	20	24	26	24
	US$/ton		107	134	161	174	
Fuel oil basket	US$/ton		75	101	127	140	
	Rs/ton		3,588	4,836	6,084	6,708	
Natural gas price	Rs/1,000scm	2,850	3,588	4,836	6,084	6,708	7,800
	US$/MBtu	1.49	1.88	2.53	3.18	3.51	4.08
Royalty	Rs/1,000scm	257	323	435	548	604	
Transportation	Rs/1,000scm	1,353	1,353	1353	1,353	1,353	1,353
16 percent sales tax	Rs/1,000scm	672	791	990	1,190	1,290	1,464
Delivered cost	Rs/1,000scm	5,132	6,054	7614	9,174	9,954	10,617
	Rs/MCal	0.51	0.60	0.76	0.91	0.99	1.06
Economic cost	Rs/1,000scm	9,153			9,153		9,153
Net subsidy	Rs/1,000scm	4,021			-22		

Generation Costs

3.41 Karnataka's generation options are limited. The state has no fossil fuel resources of its own, and is dependent upon fuel imported either from overseas or from neighboring states (as in the case of Raichur). The main options are as follows:

- Coal-burning stations located either on the west coast or at such internal locations as have sufficient water for (evaporative) cooling (for example, the proposed 500MW coal-based plant at Bellary).
- LNG-fired stations on the west coast.
- Naphtha-fired CCCT units (as were earlier proposed by several IPPs).
- Diesel generation, including barge-mounted units (again as proposed by IPPs).
- Thermal peaking units using open (simple) cycle combustion turbines (OCCTs), fueled by either naphtha or gas. To date there has been little interest in such units anywhere in India, in part as a consequence of the compulsions of the GoI tariff norms, which link incentive payments to high plant factors. Simple-cycle combustion turbines have low annual plant factors; they are however intrinsically optimal for peaking duty, making this one of the few options available for eliminating peak power shortages over the short to medium term.

Table 3.12 lists the key assumptions for capital costs of these options.[40]

Table 3.12: Capital Costs (Rs millions/MW)

	financial	economic
Coal (NTPC)	40	31
Coal (IPP)	55	45
CCCT (naphtha)	30	25
Diesel	25	22
OCCT	15	13.5

Emission Coefficients

3.42 Wherever possible, emission coefficients are calculated by stochiometry, since this is the best way to ensure consistency between assumptions about fuel characteristics, generating plant efficiency, combustion technology, and the pollution control options as may be applied.[41] Where such stochiometric calculations are not possible, we use the emission coefficients provided by the IPCC (World Bank 1997) or, in the case of clean coal technologies, by the World Bank (Oskarsson and others 1998). Table 3.13 describes the assumptions and coefficients used for each air emission.

Table 3.13: Methodology for Air Emission Calculation

Carbon	*Stochiometric calculation,* based on the carbon content of the fuel. If C is the percentage of carbon in the fuel, by weight, and f is the fraction of carbon oxidized in combustion, then the weight in kilograms of C emitted per kilogram of fuel consumed $= Cf$.
SO_2	*Stochiometric calculation,* based on the sulfur content of the fuel. If S is the percentage of sulfur in the fuel, by weight; λ is the fraction of SO_2 in the flue gas removed by FGD; and f is the fraction of sulfur oxidized in combustion, then the weight in kilograms of SO_2 emitted per kilograms of fuel consumed $= S\, f\, (1-\lambda)\, 1.998$.
Particulates	*Stochiometric calculation,* based on the ash content of the fuel. If A is the percentage of ash in the fuel by weight; f is the fraction of ash to fly ash (and $1-f$ the bottom ash fraction); and γ is the fraction of particulates removed by the ESP, then the particulate emissions per kilogram of fuel consumed $= A\, f\, (1-\gamma)$.
NO_x	*Emission factor,* as provided by the equipment manufacturer and/or as per the project-specific Environmental Impact Assessment.

[40] In this report we quote capital costs as "overnight" costs; that is, without IDC or escalation. In economic analysis, capital costs are recorded in the year disbursed—that is, they are recorded over several years for a typical multi-year construction project.

[41] A good example of why such an approach is desirable and necessary is flue gas desulfurization (FGD). Plants fitted with FGD systems will have lower overall efficiency, due to higher auxiliary consumption and impact on boiler efficiency, and FGD may therefore increase CO_2 emissions per net kWh by up to 5 percent.

Table 3.14 shows the characteristics of coals used in Karnataka at Raichur.[42]

Table 3.14: Raichur Coal Characteristics, November 2002

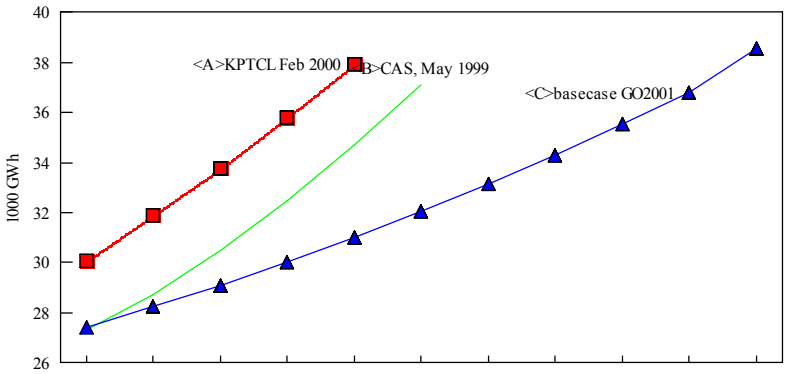
	Singareni	Singareni	WCL	WCL	Washed	MCL washed
Proximate analysis, percent						
Moisture	4.8	4.6	6.9	6.3	5.1	4.2
Volatile matter	33.1	33.1	33.1	33.3	33.3	33.1
Ash	30.7	33	33.8	32.9	32.6	39
Fixed carbon	31.4	29.3	26.2	27.5	29	23.7
Ultimate analysis, percent						
Carbon	50.93	49.05	44.98	46.31	48.25	42.86
Hydrogen	3.85	3.76	3.77	3.81	3.95	3.59
Nitrogen	0.94	0.87	0.79	0.76	0.65	0.63
Sulfur	0.74	0.88	1	0.97	0.46	0.52
Oxygen, by difference	8.04	7.84	8.79	5.95	8.99	9.2
UHV by formula (kCal/kg)	4,001	3,711	3,283	3,490	3,697	2,938
Grade	E	E	F	E	E	F
GCV (kCal/kg)	4,967	4,780	4,370	4,542	4,745	4,273

Source: KPCL

Load Forecasts

3.43 Figure 3.6 shows a comparison of the main load forecasts expressed as the generation requirement at the busbar. It is evident that the forecast of the 2001 Government Order (GoI 2001) is significantly below the forecast made by KPTCL in February 2000 and that made by Crisil Advisory Services in May 1999.

Figure 3.6: Unconstrained Energy Forecast (at the Busbar)



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
<A>KPTCL Feb 2000	30.1	31.9	33.8	35.8	38.0						
<B>CAS, May 1999	27.3	28.7	30.5	32.5	34.7	37.1					
<C>basecase GO2001	27.4	28.2	29.1	30.0	31.0	32.0	33.1	34.3	35.5	36.8	38.6

[42] The carbon fraction of Indian coals is sometimes taken as per the relationship discussed in a 1993 TERI study, namely

$$f = 0.017 + 0.0248 \text{ GCV (GJ/tonne)}$$

where GCV is the gross calorific value (TERI 1993). In Chapter 2 of this study the "average" carbon fraction of Indian coals is given as 59 percent by weight (Mehra and Damodaran 1993).

3.44 It is evident (see Figure 2.1) that over the past decade a substantial proportion of the industrial load that would under normal circumstances have connected to the grid is now supplied through self-generation. A major question for future demand consequently is how much of this can be captured back by the grid as supply conditions improve and as the HT tariff declines again, in real terms. Most diesel units, with the exception of those using heavy fuel oil and those serving critical demand that cannot tolerate even brief interruptions, are now returning to the grid: as noted earlier, the recent increases in the price of HSD have made captive generation uneconomic. When HSD was Rs 11/liter, as in the mid-1990s, the variable cost of generation fell to Rs 2.75/kWh, or substantially less than the Rs 4/kWh HT tariff of 1998 (Figure 2.1).[43] At the current price of Rs 22/liter, the variable cost is Rs 4.50/kWh, which is substantially more than the HT tariff. Table 3.15 shows our estimate of the total demand that was supplied by self-generation in 2001.

Table 3.15: 2001 Energy Reconciliation (in GWh)

	Sales	NT-loss	Grid demand	Actual demand	Curtail-ment	Met by self-generation	Not met
	[1]	[2]	[3]	[4]	[5]	[6]	[7]
Domestic	3,606	1,545	5,151	6,650	1,500	-	1,500
Commercial	711	305	1,016	1,300	300	200	100
Other LT	789	88	877	967	90	-	0
LT industry	1,378	288	1,666	1,866	200	200	200
Agriculture	7,227	803	8,030	12,000	4,000	-	4,000
HT industry	2,363	0	2,363	2,600	140	140	0
HT other	1,398	0	1,398	1,600	200	-	200

3.45 The original 2001 Government Order (GO) forecast applied a constant, nontechnical loss rate of 11 percent of total generation to all consumption categories. It is highly unlikely, however, that all consumers have the same rate of pilferage. It is more useful to express nontechnical losses as a fraction of consumption, such that the rate directly expresses the rate of pilferage and non- or defective metering. Table 3.16 shows an alternative reconciliation of T&D loss rates, segregated into nontechnical, LT technical (distribution), and HT technical (transmission). Reconciled to the same nontechnical loss rate of 11 percent of total generation, this indicates that loss rates of as much as 30 percent of domestic demand (consumption) are probable.

[43] Based on the standard assumption of 0.25 liters/kWh.

Table 3.16: Reconciliation of T&D losses

	Sales	NT losses	Fx (NT)	Dem.	Tech losses LT	Fx (LT)	Total LT	Tech losses (HT)	Fx (HT)	Total gener	T(x)	F(x)
	[1]	[2]	[3]	[4]= [1+3]	[5]	[6]	[7]= [4+5]	[8]	[9]	[10]= [7+8]	[11]= [5+8]	[12]
Dom.	3606	1545	0.3	5151	1292	0.2	6444	339	0.05	6783	6783	0.241
Comm.	711	305	0.3	1016	255	0.2	1271	67	0.05	1337	1337	0.241
Other LT	789	88	0.1	877	220	0.2	1097	58	0.05	1154	1154	0.241
Industry	1378	288	0.17	1666	418	0.2	2084	110	0.05	2194	2194	0.241
Agr.	7227			8030	3433	0.2	11485	604	0.05	12089	12089	0.336
HT ind.	2363	803	0.10	2363			2363	124	0.05	2487	2487	0.05
other HT	1398			1398		0.3	1398	74	0.05	1472	1472	0.05
total	17472	3209		20501	5640		26141	1376		27517	7016	0.255

3.46 For long-range planning purposes is it desirable to have a model representation of demand growth that is explicitly linked to exogenously specified planning assumptions such as the GDP growth rate and the rate of real tariff growth (together with assumptions about price and income elasticities).[44] We therefore have constructed a simple econometric model calibrated to the baseline forecast, so that it exactly replicates the Indian Government forecast to 2010 using the anticipated economic growth rate under the reform program. The econometric model takes the form:[45]

$$Q_t = Q_{t-1}\left(\frac{Y_t}{Y_{t-1}}\right)^{\alpha}\left(\frac{P_t}{P_{t-1}}\right)^{\beta} \qquad \text{Equation [3.1]}$$

where P_t = real price in year t

Y_t = real income in year t

α = income elasticity of demand

β= price elasticity of demand

Q_t = electricity demand in year t

[44] Missing from this specification is the price of the substitute fuel, which plays a key role particularly for industrial consumption. When the variable cost of diesel fuel per kWh is above the grid price, as occurred in the mid-1990s, there is strong incentive for captive generation.

[45] For statistical estimation purposes this model would need to be extended to include the price of substitute fuel (notably that of HSD for captive generation in the HT industrial category).

To replicate the GO forecast to 2010, we calculate income elasticities for each customer class and each time interval as

$$\alpha_t = \frac{\ln\left(\frac{Q_t}{Q_{t-1}}\right) - \beta \ln\left(\frac{P_t}{P_{t-1}}\right)}{\ln(1+g_t)} \qquad \text{Equation [3.2]}$$

where g_t is the assumed growth rate of GSDP and β is the price elasticity applied to the real tariff. The GO forecast does not (apparently) consider price elasticity; this is equivalent to inelastic behavior, so $\beta = 0$ and Equation [3.2] reduces to

$$\alpha_t = \frac{\ln\left(\frac{Q_t}{Q_{t-1}}\right)}{\ln(1+g_t)} \qquad \text{Equation [3.3]}$$

The forecast is then extended to 2021 to complete the 20-year planning horizon by insertion of these income elasticities into Equation [3.1].

3.47 Ignoring price elasticity is often justified on the basis of the absence of reliable econometric studies.[46] However, ignoring price elasticity equates to an assumption of perfectly inelastic behavior. Given no specific information in a particular location about actual consumer behavior, this is not the most reasonable assumption: given the worldwide experience, assuming some reasonable non-zero value for price elasticity almost certainly involves less error than assuming its value at zero.

3.48 There appear to be no assumptions regarding price elasticity in any of the studies of the Karnataka power sector, yet, as shown in the case of HT industrial demand, there is clear evidence of price-elastic behavior (Figure 2.1). The values of price elasticity used in the other EIPS case studies are shown in Table 3.17.

Table 3.17: Estimates of Price Elasticities

	Uttar Pradesh	EIPS special study	Andhra Pradesh	Adopted for this report
Domestic	-0.24	-0.45	-0.4	-0.4
Commercial	-0.07	-0.49	-0.4	-0.4
Industrial	-0.15 to -0.35			
Agricultural	-0.4 to -0.76	-1.23	-0.2	-0.4
LT industry		0	-0.3	-0.3
HT industry		-0.45	-0.3	-0.33

Sources: Ewbank Preece (1996),TERI (1997), and the Administrative Staff College of India (1998).

[46] For example, in Uttar Pradesh Ewbank-Preece notes, "we similarly found macroeconomic data which would be required for forecasting using demand elasticities also proved to be insufficiently detailed to enable a forecast to be prepared. ... [T]his would result in a forecast based on a number of important assumptions, and could therefore prove to be highly inaccurate. ... [I]t is particularly difficult to assess the price elasticity of demand for electricity on a historical basis since price has, for many categories, been held at artificially low levels in Uttar Pradesh" (Ewbank Preece, 1996).

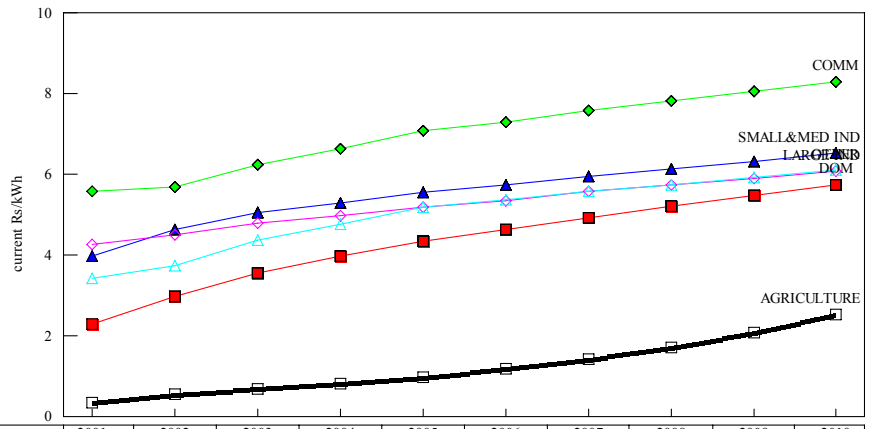
3.49 With these income and price elasticities in hand, we may undertake a set of consistently specified base forecasts for the no reform and reform cases, based on the assumptions enumerated in Table 3.18. In the no reform case T&D losses would be expected to increase over present levels, as the lack of financial resources would prevent the necessary upgrade of the T&D system as loads increase (and as rates of distribution transformer failure increase).

Table 3.18: Assumptions for Load Forecasts

	Reform (consistent with GO)	Stalled reform	Price-elastic forecast
$GSDP_{growth}$	5.5 percent per year	5.5 percent per year	Econometric projection (function of tariff and GDP assumptions)
Tariff	As per GO	No increases	
T&D losses	As per GO	No change over 2002 levels	
Price elasticity	Not considered	Not considered	As given in Table 3.15

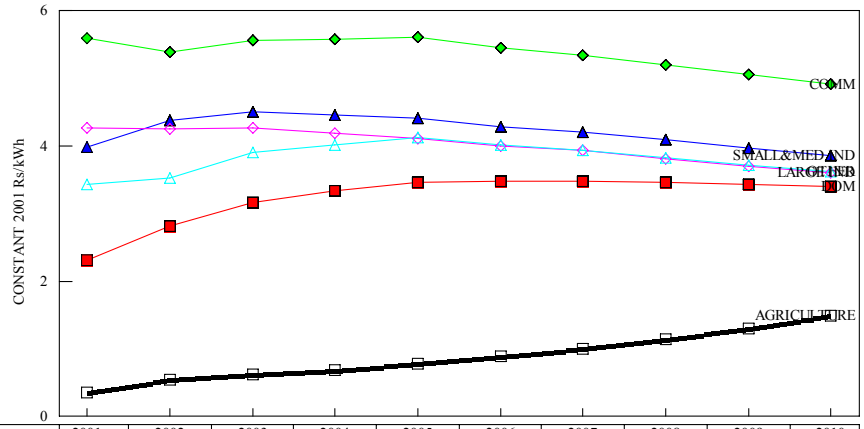
3.50 Figure 3.7 shows the baseline tariff forecast in current rupees and Figure 3.8 the corresponding tariff in real terms. From 2003 onward the real tariff for industry declines somewhat; that of agriculture more than triples by 2010 to Rs 2.5 (in constant 2001 rupees).

Figure 3.7: Tariff Projections for the Reform Program (Current Rupees)



	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
DOM	2.3	3.0	3.6	4.0	4.4	4.6	4.9	5.2	5.5	5.8
COMM	5.6	5.7	6.2	6.6	7.1	7.3	7.6	7.8	8.1	8.3
SMALL&MED IND	4.0	4.6	5.1	5.3	5.6	5.7	6.0	6.1	6.3	6.5
AGRICULTURE	0.4	0.6	0.7	0.8	1.0	1.2	1.4	1.7	2.1	2.5
LARGE IND	4.3	4.5	4.8	5.0	5.2	5.4	5.6	5.7	5.9	6.1
OTHER	3.4	3.7	4.4	4.8	5.2	5.4	5.6	5.8	5.9	6.1

Figure 3.8: Tariff Projections for the Reform Case (Constant 2001 Rupees)



	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
DOM	2.3	2.8	3.2	3.3	3.5	3.5	3.5	3.5	3.4	3.4
COMM	5.6	5.4	5.6	5.6	5.6	5.4	5.3	5.2	5.1	4.9
SMALL&MED IND	4.0	4.4	4.5	4.4	4.4	4.3	4.2	4.1	4.0	3.9
AGRICULTURE	0.4	0.5	0.6	0.7	0.8	0.9	1.0	1.1	1.3	1.5
LARGE IND	4.3	4.3	4.3	4.2	4.1	4.0	3.9	3.8	3.7	3.6
OTHER	3.4	3.5	3.9	4.0	4.1	4.0	3.9	3.8	3.7	3.6

Load Shapes

3.51 Important seasonalities characterize both the supply and demand side. On the supply side are significant variations in hydroelectric generation, while on the demand side agricultural demands are particularly related to season (and need careful specification for the evaluation of potential DSM options). However, the presently observed load shapes are highly distorted as a result of peaking power shortages, and are much flatter than those that can be expected as sector reform eliminates supply shortages and the hourly demand patterns return to their classical shape. Figure 3.9 shows typical (restricted) load shapes for 2002, some of which curves reflect a high degree of management and skill in making best use of the available resources. The sharp drop in the agricultural load during the evening peak reflects the need to accommodate the evening peak in domestic and commercial sectors.

3.52 In the absence of supply curtailments, the load shape would look quite different, in particular demonstrating a more pronounced morning and evening peak. Integrated over the year the load shape would show in a much lower system load factor (Figure 3.10).

Figure 3.9: Constrained Load Curves, Selected Days, 2002

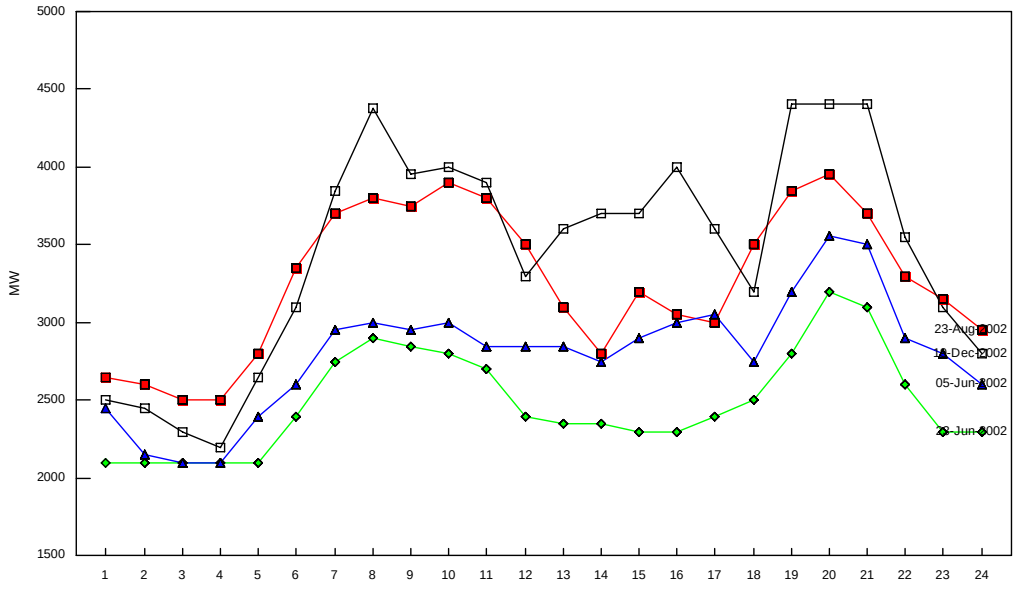
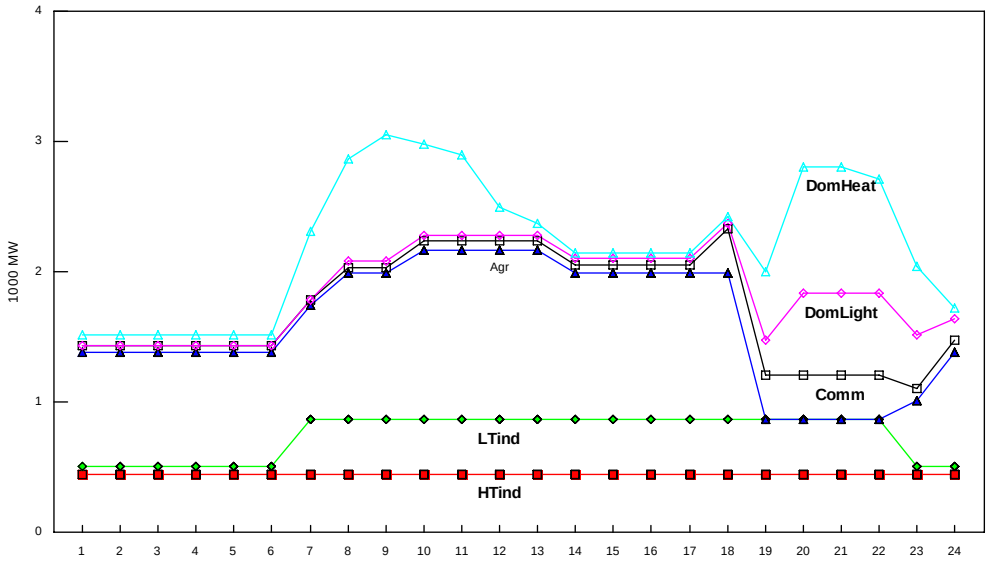


Figure 3.10: Synthesized Load Shape for Unconstrained Consumption



3.53 For the impact of technical loss reduction programs to be properly assessed, the average annual loss rates in energy terms cannot simply be applied linearly, because technical losses are proportional to the square of the load. The necessary calculations are as follows:

- express the unconstrained daily load curves in cumulative form for each of the three seasons;
- linearize the load curves (representing each day as peak1, peak2, intermediate, and off-peak);
- assign the average annual T&D losses to each of the 12-blocks in the load curve, based on the square of their respective MW loads.

4

Definition of Scenarios

The Baseline Reform Scenario

4.1 The baseline reform scenario reflects the assumptions of the September 2001 Government Order (GO), therein described as "base case with moderate tariff increase scenario." The critical assumptions that describe the physical development of the power sector are as follows:

- Technical losses reduced from 26 percent to 21 percent by 2005, and to 14 percent by 2010.
- Commercial losses reduced from 11 percent to 7 percent by 2005, and to 2 percent by 2010.
- Energization of new pump-sets not to exceed 40,000 pump-sets per annum.
- Tariff increase by 12 percent per year for the first five years and 9 percent for 10 years.
- Additional capacity of 2,325MW in five years and 3,101MW in 10 years.
- Annual overall growth in consumption of about 5 percent (domestic, 7.62 percent; IP sets, 3 percent; commercial low tension, 8.22 percent; industrial low tension, 6.25 percent; industrial high tension, 5.06 percent).

4.2 This scenario is then extended to 2021 to complete the 20-year planning horizon. On the demand side we extrapolate the load forecasts as described in Section 3; on the supply side, the capacity expansion plan that is envisaged until 2010 is as shown in Table 4.1 (which reproduces the relevant Annexure of GO 2001). Thereafter Enviroplan builds the least-cost expansion plan for generating capacity as required to meet the load forecast.

4.3 With reform, the constraint would be removed that for each year a state should exactly balance its demand with its own supply and the fixed contributions from central plants. Small supply-demand imbalances, or those that will arise in cases where the optimal capacity expansion plan, seeking to exploit scale economies, builds units

larger than necessary to meet a single year's demand growth, can be assumed to be equilibrated by purchases and sales to the Power Trading Corporation (PTC). As the State Electricity Boards become creditworthy, such equilibrating trade will become a routine feature familiar to the regional markets of Europe and North America.

Table 4.1: The Baseline Capacity Expansion Plan

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Existing sources										
KPCL-Hydel	74	75	8	8	8			1		
Raichur 7				210						
NLC Neyveli I	35									
NLC Neyveli II	45									
NLC additional		38	248		250					
NPVC-Kaiga	54									
NTPC: Talcher				116	116	232				
NTPC-Cheyur							87	87		
NTPC-Ramagundam						87				
Eastern Region						-110				
Jindal						-100				
Cogeneration		64	54	30						
VVNL			14							
Total	208	177	325	364	461	22	87	88	0	0
Contracted sources										
Tannerbhavi	220								-220	
Rayalaseema	27									
Tata		81								
Almatti (UKP)(1)		297								
Total	247	378	0	0	0	0	0	0	-220	0
Grand total	456	557	325	364	461	22	87	88	-220	0

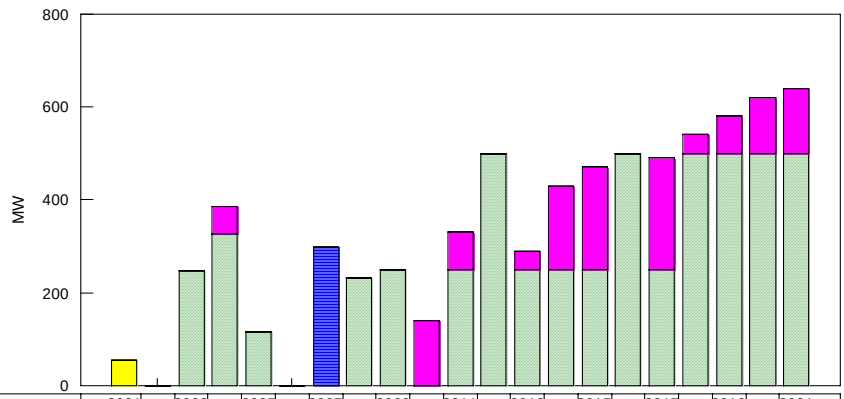
Source: *GoI (2001)*

(1) The Government Order shows this as a contracted source (Chamundi Power Company). This project has however now reverted to KPCL, and is likely to be significantly delayed over the original timetable.

4.4 The model extends the expansion plan to 2021, based on the assumption that base load capacity additions will be located on the west coast, using domestic coal shipped from Paradeep by coastal freighter (Figure 4.1).

4.5 As noted earlier, this is not the least-cost solution in terms of economic costs, but is the financial least-cost given the current rate of customs duty on imported coal of 29.5 percent. The consequences of other assumptions about where coal-based plants could be located and about alternative fuel sources, notably pipeline gas from the new gas finds in the Bay of Bengal, are examined below.

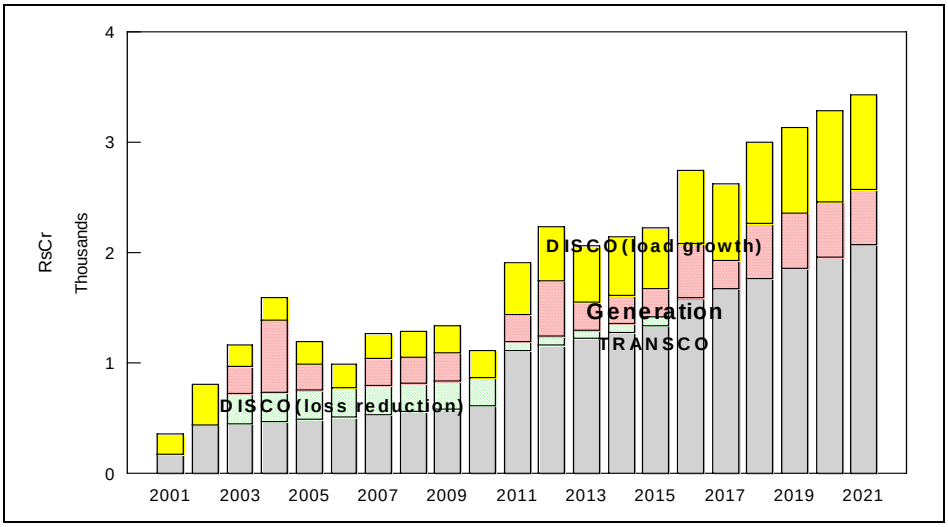
Figure 4.1: Baseline Expansion Plan



	2001		2003		2005		2007		2009		2011		2013		2015		2017		2019		2021
hydro	0	0	0	0	0	0	297	0	0	0	0	0	0	0	0	0	0	0	0	0	0
coal	0	0	248	326	116	0	0	232	250	0	250	500	250	250	250	500	250	500	500	500	500
gas/lng	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
nuclear	54	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LQ	0	0	0	60	0	0	0	0	0	140	80	0	40	180	220	0	240	40	80	120	140
renewables	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

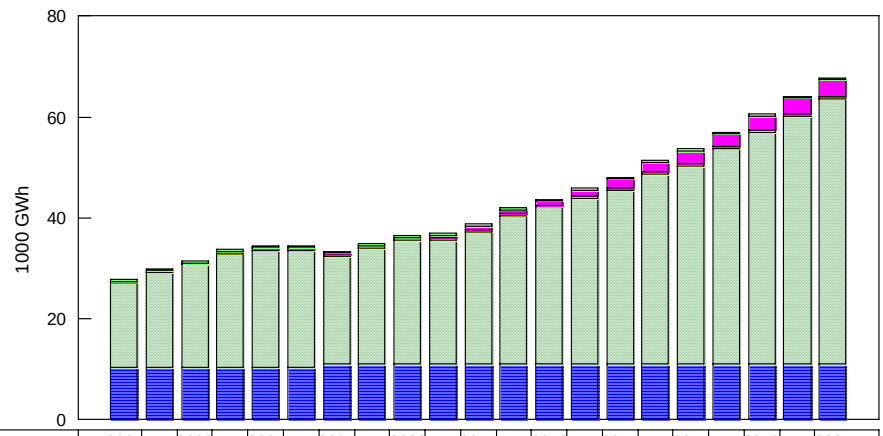
4.6 Figure 4.2 shows the corresponding transmission line investment requirements. This is broken down into four categories: (a) TRANSCO investment in the transmission system; (b) incremental transmission costs associated with new generation facilities, such as the HVDC link between Talcher II and Bangalore, assumed made by Powergrid); (c) DISCO investment for technical loss reduction (the bulk of which is assumed spent in 2003–2010); and (d) DISCO investment in the distribution system to accommodate load growth and new connections.

Figure 4.2: Transmission and Distribution Investment



4.7 The corresponding generation mix is shown in Figure 4.3. The hydro share decreases from 37 percent to 16 percent over the planning horizon, since all of the capacity additions in the base case, with the exception of Almatti, are thermal. The vast majority of additions are coal, as shown in Figure 4.1.

Figure 4.3: The Generation Mix (TWh)



	2001		2003		2005		2007		2009		2011		2013		2015		2017		2019		2021
hydro	10	10	10	10	10	10	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
coal	17	19	20	22	23	23	21	23	24	24	26	29	31	33	34	38	39	43	46	49	52
gas/lng	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LQ	0	0	0	0	0	0	0	0	0	1	1	1	1	1	2	2	3	3	3	3	4
renewables	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

4.8 The Enviroplan economic analysis is shown in Table 4.2. Each of the major cost and benefit streams is identified, including the monetization of environmental externalities (with carbon valued at US$15/ton).[47] The average incremental production cost, as a proxy for the long-run marginal cost of supply, including T&D investment, is Rs 3.03/kWh.

[47] US$15/ton carbon is used by the Prototype Carbon Fund (PCF) as a representative average of willingness-to-pay. The PCF has set US$20/ton as the target price outcome averaged across the PCF portfolio at the end of carbon purchase agreements entered into; the current emissions reduction cost screening criterion for PCF eligibility is US$10/ton carbon. See PCF (2002).

Table 4.2. Economic analysis: Reform GO 2001

		NPV	2001	2002	2003	2004	2005	2006	2007	2008
BENEFITS										
grid supplied	[RsCr]	82061	7062	7521	8004	8514	9052	9620	10219	10851
self-generation	[RsCr]	0	0	0	0	0	0	0	0	0
DSM	[RsCr]	0	0	0	0	0	0	0	0	0
exportable surplus (sales to PTC)	[RsCr]	0	0	0	0	0	0	0	0	0
total benefits	[RsCr]	82061	7062	7521	8004	8514	9052	9620	10219	10851
COSTS										
capital costs										
grid generation plants	[RsCr]	7369	769	1011	438	0	960	928	1078	26
..less salvage value	[RsCr]	-1215								
pollution mitigation[FGD, etc]	[RsCr]	0								
T&D investments	[RsCr]	10624	411	802	1158	1588	1195	991	1260	1283
self-generation plant	[RsCr]	0	0	0	0	0	0	0	0	0
DSM investments	[RsCr]	0	0	0	0	0	0	0	0	0
renewable energy	[RsCr]	0	0	0	0	0	0	0	0	0
total capital costs	[RsCr]	16779	1179	1812	1596	1588	2155	1919	2338	1309
O&M costs										
spot purchases from PTC	[RsCr]	5275	3866	540	0	0	0	0	2418	742
fuel	[RsCr]	12182	1032	1194	1270	1249	1286	1354	1300	1441
other non fuelO&M costs	[RsCr]	1015	69	95	115	126	135	140	144	148
G&A costs	[RsCr]	6728	653	816	793	788	802	831	860	890
other costs	[RsCr]	13538	3163	2846	2562	2306	2075	1868	1681	1513
fuel, self-gen plants	[RsCr]	0	0	0	0	0	0	0	0	0
DSM[admin costs]	[RsCr]	0	0	0	0	0	0	0	0	0
DSM device O&M	[RsCr]	0	0	0	0	0	0	0	0	0
renewable energy	[RsCr]	0	0	0	0	0	0	0	0	0
total O&M	[RsCr]	38738	8781	5491	4740	4468	4298	4193	6402	4733
Environmental damage costs in Karnataka										
PM-10	[RsCr]	615	41	49	56	62	69	77	79	84
SOx	[RsCr]	172	11	14	15	17	19	21	22	23
NOx	[RsCr]	434	26	32	36	40	45	50	51	55
total environmental damage costs	[RsCr]	1220	79	95	107	119	133	149	152	163
consumptive water use	[RsCr]	796	103	103	108	101	102	106	110	110
Global:GHG 15 $/ton	[RsCr]	3282	294	337	357	358	370	388	371	402
total costs	[RsCr]	117968	10142	7501	6551	6276	6687	6366	9002	6315
net economic flows [production+local-ε	[RsCr]	24527	-3080	20	1453	2238	2365	3254	1217	4536
net economic flows [production+local-ε	[RsCr]	27809	-2786	356	1810	2596	2735	3642	1588	4937
net economic flows [production]	[RsCr]	26543	-2898	217	1668	2458	2600	3509	1479	4809
memo items										
served demand	[GWh]	229972	21931	22926	23966	25052	26188	27375	28617	29916
Economic cost of power [production co	[Rs/kWh]	2.41	4.54	3.19	2.64	2.42	2.46	2.23	3.05	2.02
incremental GWh served	[GWh]	64129		995	2035	3121	4257	5444	6686	7985
incremental costs	[RsCr]	19457		1816	1676	1646	2250	2083	2566	1678
Average incremental cost (as proxy for	[Rs/kWh]	3.03								

Note: Extract only; all calculations carried to 2021
1 Crore [RsCr] = 10 million

4.9 The results may also be displayed in terms of the distributional impacts on the stakeholders, as shown in Table 4.3. The columns of this table represent the stakeholders, and the rows the individual transactions. Columns 9 and 13 represent the economic costs and benefits, in which all the transfer payments (duties, taxes, cross-subsidies, and so forth) cancel out (column 9 before consideration of the environment and column 13 with consideration of the environment, for which carbon emissions are valued at US$15/ton and local emissions are valued as discussed in Section 3). All figures are in Rs Crores, at constant 2002 price levels, expressed as NPV over 20 years at a 12 percent discount rate.

Table 4.3: Distributional Impacts Among Stakeholders

	Karnataka					Karnataka			economic	environment			economic
	power sector	GoK	IPPs	Other State Govts.	Central Govt.	Pilferers	Consumers	GEF/ MNES/ CDM	before ENV	local air	water	global	with ENV
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
consumer benefits													
grid electricity						1697	82061		83758				83758
DSM							0		0				
self-gen electricity							0		0				0
total						1697	82061		83758				83758
consumer costs													
self-gen							0		0				0
DSM							0		0				0
out-of state consumer benefits				0					0				0
tariff	51847						-51847		0				0
cost of power generation	-51457								-51457				-51457
power sales to others	0			0					0				
environmental impacts													
Karnataka										-1220	-796		-2016
out-of-state										-415			-415
global												-3282	-3282
returns													
Central sector	-425				425				0				0
IPPsEquityReturns	-937		937						0				0
Govt dividends	-3499	3499							0				0
renewable energy	0		0										
Revenue subsidy	7478	-7478							0				0
GEF&MNES subsidies	0							0	0				0
taxes,duties, subsidies													
Electricity duty		0					0		0				0
Customs duty	0				0				0				0
free hydroPower	0			0					0				0
CST(coal)	-365				365				0				0
nuclear subsidy	0				0				0				0
coal Royalties	-841			841					0				0
Excise Duties	-1799				1799				0				0
total	-0	-3979	937	841	2590	1697	30214	0	32301	-1635	-796	-3282	26588

4.10 In Table 4.3 and subsequent tables and graphs the following abbreviations apply:

- "GoK" represents the total flow of funds to/from the power sector and the Government of Karnataka
- "power sector" represents the aggregate of the unbundled entities in the power sector. The aggregate cash flow of these entities is always zero, because either their shortfall is covered by government revenue subsidy or their surplus is distributed to the respective equity investors (but is included in the revenue requirements from 2010 onward)

- "IPPs" represents the equity returns to IPP developers
- "other State Govts" represents other state governments that benefit from the royalties for coal supplied to Karnataka
- "Central Government" represents the net flow of funds to/from the Government of India due to sales tax, excise duties, customs duty, and equity returns on the GoI's investment on behalf of Karnataka's power sector (for example, the Powergrid investment in HVDC transmission to bring power from Talcher II to south India)
- "Pilferers" represents the benefits associated with the consumption by those who do not pay. When pilferers consume electricity they derive an economic benefit from that consumption, and this needs to be considered in the analysis. This benefit is, however, generally smaller than the economic cost of supplying the pilferer, with the result that metering and the reduction of nontechnical losses bring significant economic benefit
- "GEF/MNES/CDM" represents any subsidies paid for renewable energy projects by the Global Environment Facility and the Ministry of Nonconventional Energy Sources, or carbon revenues realized through projects associated with the Clean Development Mechanism of the Kyoto Protocol
- "local air" represents the environmental damage costs associated with local air emissions
- "water" represents the opportunity cost for consumptive freshwater use (for example, a steam-cycle thermal project consumes some 3.75 liters of water for every kWh generated, but a gas-fired combined cycle plant consumes only one-third of this amount). This is not an issue for coastal plants, but is an issue for any thermal project sited in the major freshwater basins of the Krishna and Cauvery Rivers
- "Global environment" represents the benefit to the global environment of the reduction of carbon emissions, assumed here at US$15/ton carbon

4.11 Figure 4.5 shows the projected tariffs (in constant Rs/kWh), and illustrates the working of the financial module in Enviroplan. The tariff as calculated from an analysis of revenue requirements is shown as "RRtariff." This is the tariff that is necessary to cover all financial requirements without government subsidy (but including a return on equity). The "actual tariff" is the tariff as seen by consumers: between now and 2010 it is interpolated linearly to the calculated tariff in 2010 (with any necessary subsidy covered by the GoK). After 2010 it is assumed that that the actual tariff and the RRtariff are the same; these trend downward as the reduction in losses and greater operational efficiency works its way through the revenue requirement calculations.

Figure 4.4: Distribution of Costs and Benefits

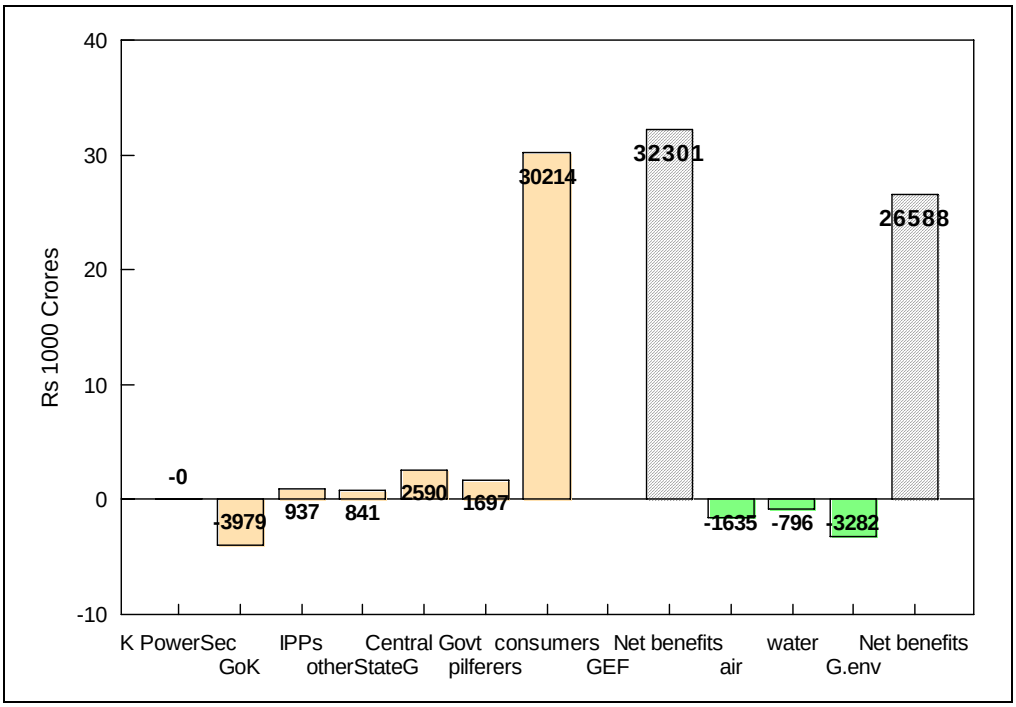
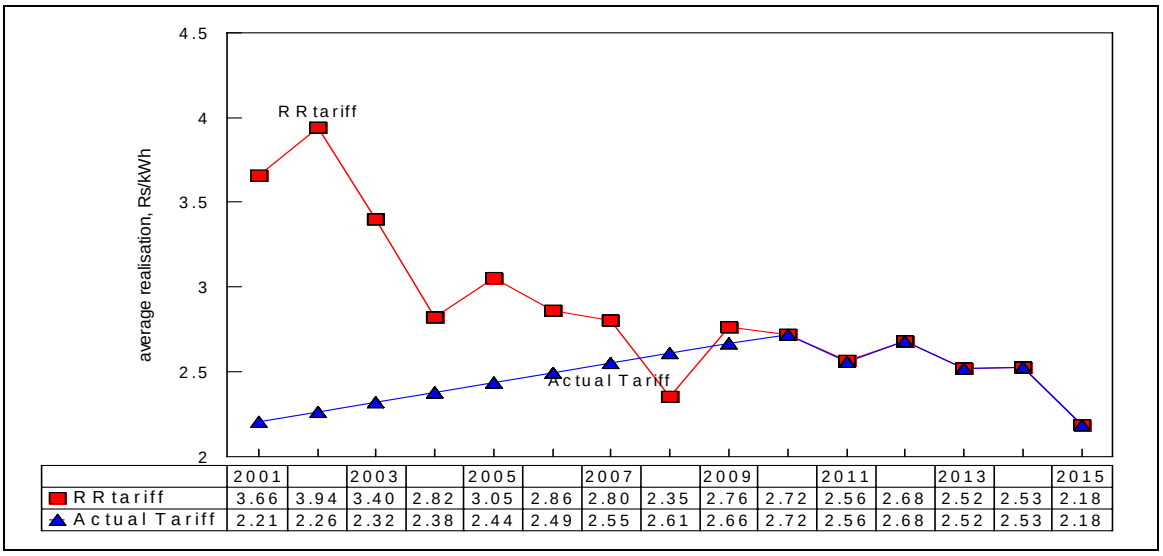


Figure 4.5: Tariff Projections



	2001		2003		2005		2007		2009		2011		2013		2015
R R tariff	3.66	3.94	3.40	2.82	3.05	2.86	2.80	2.35	2.76	2.72	2.56	2.68	2.52	2.53	2.18
Actual Tariff	2.21	2.26	2.32	2.38	2.44	2.49	2.55	2.61	2.66	2.72	2.56	2.68	2.52	2.53	2.18

The Stalled Reform Scenario

4.12 Karnataka is committed to reform, making discussion of a "no reform" scenario seem redundant, particularly given that a number of the steps already taken may be regarded as essentially irreversible.[48] However, assessing the environmental and economic impacts of reform is an important question for the overall study, and is particularly important for other states that have yet to embark on a reform program. In the case of Karnataka the most useful comparative scenario would be to assume that the goals set out in the 2001 Government Order are not implemented over the recommended timetable, for which one may hypothesize the following consequences:

- The use of spot PTC purchases and sales as the balancing mechanism for the capacity expansion plan is no longer possible, as the sector is not likely to become creditworthy absent further progress on reform.
- No additional IPP projects reach financial closure, and additional energy and capacity is supplied only from central projects, to a maximum of 250MW per year (reflecting the current rate of additions).
- Investment in T&D continues to lag: technical and nontechnical T&D losses are assumed stalled at their 2003 levels.
- There is no further adjustment of tariffs, in real terms.

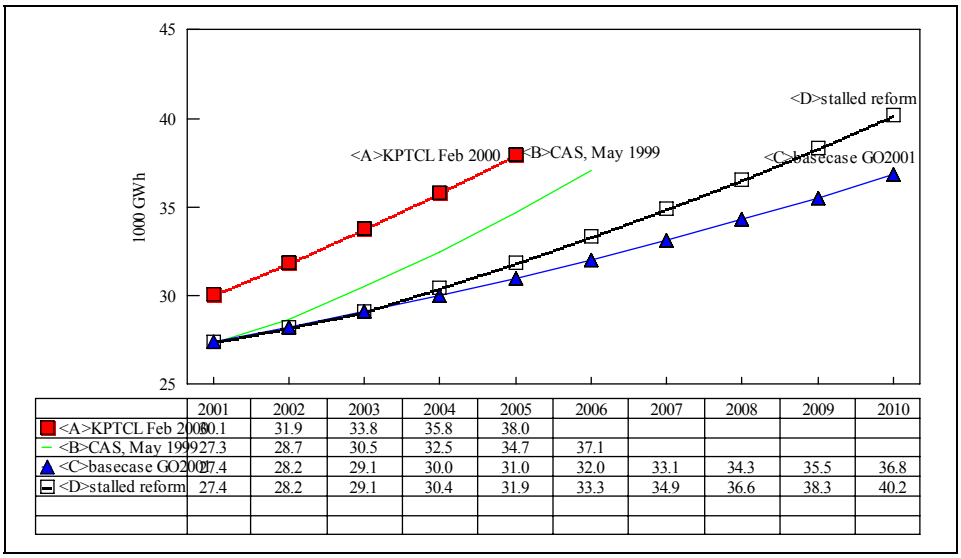
4.13 These are all exogenous assumptions rather than the result of our models. On IPPs the assumptions follow from detailed financial modeling undertaken by other consultants, such as ICICI (1997); these consultants are clear in their conclusions that, absent reform, there is insufficient escrow capacity to bring IPPs to closure. The assumptions of lack of further tariff adjustment and lagging T&D investment in the absence of reform follow directly from the years of experience immediately preceding Karnataka's commitment to reform.

4.14 Under these assumptions of stalled reform, the busbar generation requirements are 10 percent higher in 2010 because progress in reducing T&D losses slows (Figure 4.6).

---

[48] In the Bihar and AP case studies, as well as in the EIPS report, the "no reform" scenario is described as business as usual." In Karnataka "business as usual" refers to the reform path as envisaged in the GO, so the term "stalled reform" is used here instead.

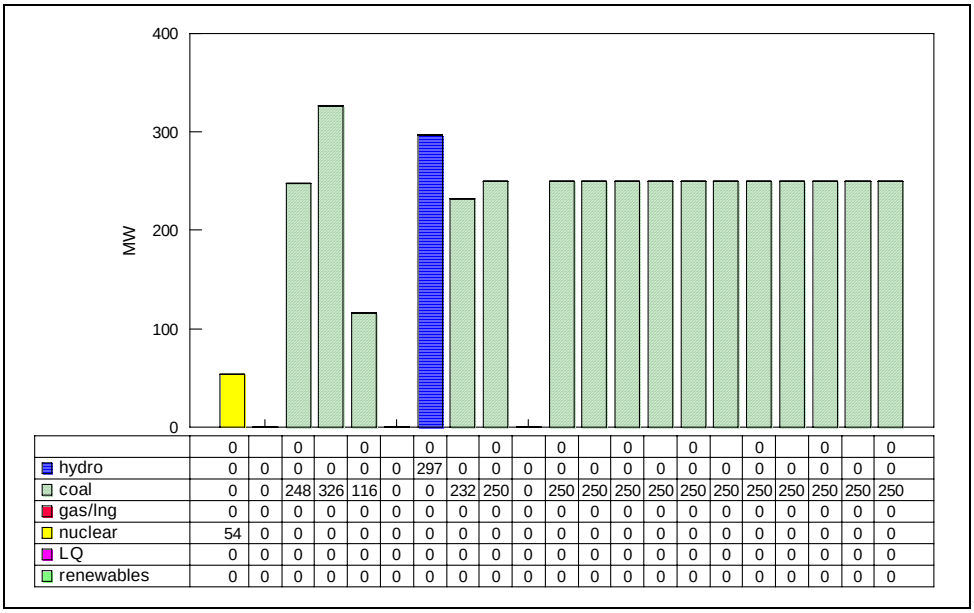
Figure 4.6: Busbar Generation Requirements—Stalled Reform



	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
<A>KPTCL Feb 2000	30.1	31.9	33.8	35.8	38.0					
<B>CAS, May 1999	27.3	28.7	30.5	32.5	34.7	37.1				
<C>basecase GO2001	27.4	28.2	29.1	30.0	31.0	32.0	33.1	34.3	35.5	36.8
<D>stalled reform	27.4	28.2	29.1	30.4	31.9	33.3	34.9	36.6	38.3	40.2

4.15 The corresponding capacity expansion plan is shown in Figure 4.7. There are no additional IPPs (beyond those in the GO plan); base load additions are limited to coal plants supplied (we assume) by the National Thermal Power Corporation (NTPC).

Figure 4.7: Expansion Plan—Stalled Reform

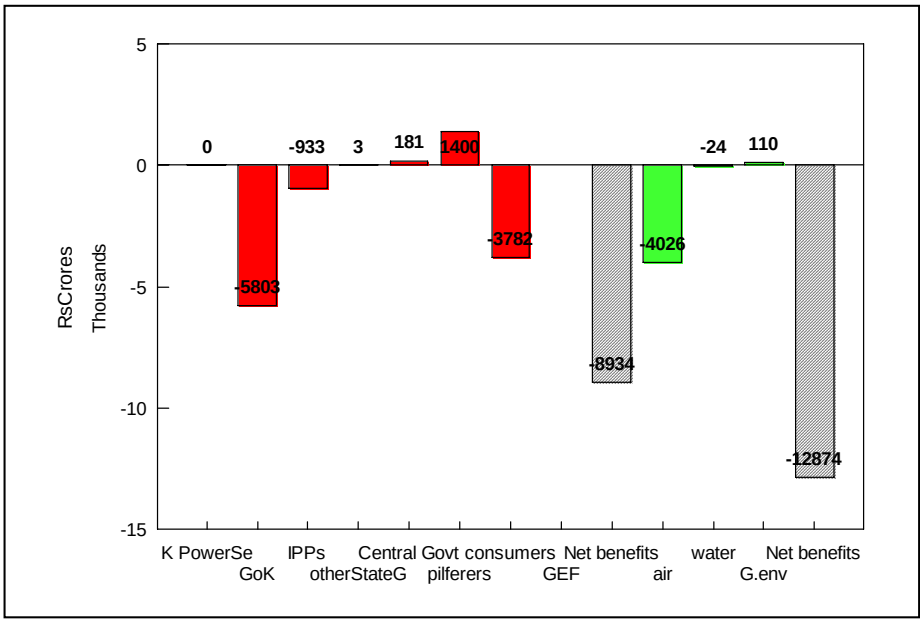


	0		0		0		0		0		0		0		0		0		0		0
hydro	0	0	0	0	0	0	297	0	0	0	0	0	0	0	0	0	0	0	0	0	0
coal	0	0	248	326	116	0	0	232	250	0	250	250	250	250	250	250	250	250	250	250	250
gas/lng	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
nuclear	54	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LQ	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
renewables	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

4.16 The consequences of a failure to reach the reform goals are severe:

- The PV of unserved energy is 7,850GWh. Self-generation increases by 5,290GWh (as PV).
- The net economic benefits (as NPV) decrease by Rs 89.34 billion when environmental externalities are not taken into account, and to Rs 128.74 billion when they are taken into account (Figure 4.8).

Figure 4.8: Distribution of Costs and Benefits of Stalled Reform (Against Reform Baseline)



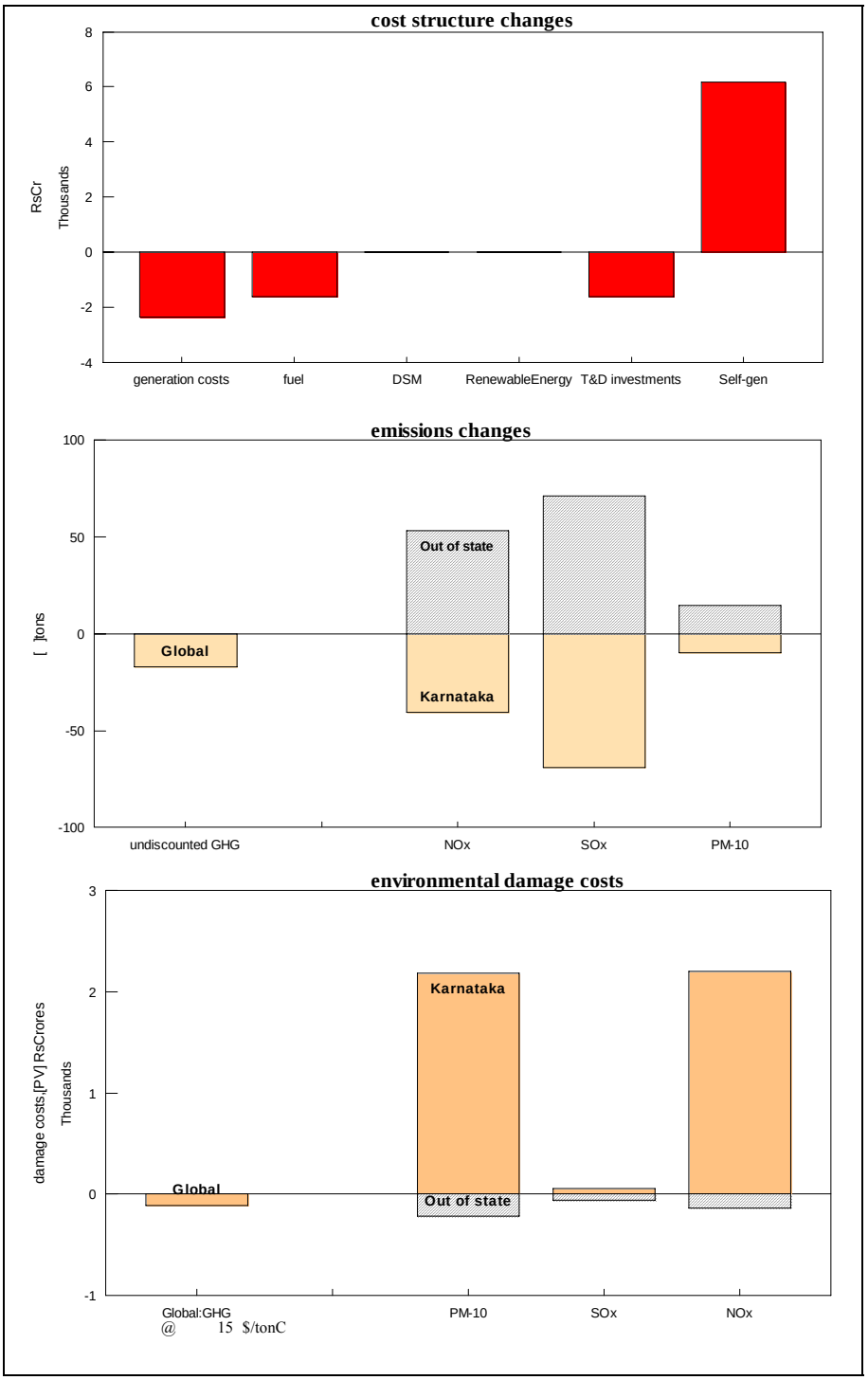
- With the exception of NOx, the physical quantities of local air emissions all show slight decreases, but the expected value of health damages increases by Rs 40.26 billion. This is a consequence of a shift to diesel self-generation, the emissions of which generally occur at ground level and in close proximity to urban populations, and whose damage costs as a consequence are high.
- Carbon emissions decline somewhat as the total fossil fuel use decreases, for a (discounted) global environmental benefit at US$15/ton of carbon of Rs 1.1 billion. However, given India's low per capita GHG emissions, it would be absurd to argue that holding up reforms would be a desirable method of reducing GHG emissions—as is evident when one considers that the avoided cost of carbon is US$127/ton.

- The cost structure of the sector changes is as indicated in Figure 4.9: utility generation and T&D investment fall and investment in self-generation increases by almost Rs 60 billion (as NPV).
- The average incremental cost (AIC) increases to Rs 3.54/kWh. (The complete economic analysis is shown in Table 4.8.)

4.17 There are two additional benefits of reform (or costs of stalled reform), not expressly quantified here, that are related to supply quality. First, the investment in T&D loss reduction reduces the overloading of LT distribution lines and will reduce distribution transformer failure rates, thus substantially reducing also the repair costs to the DISCOs.[49] Second, the improved voltage profiles of LT lines will reduce the frequency of repair to agricultural pump-sets, which prior to reform typically needed rewinding several times per season. The avoided costs of this motor rewinding, typically amounting to Rs 8,000–10,000 per pump-set per year, is an additional benefit to reform.

[49] In Andhra Pradesh, the NPV of distribution transformer repair savings in the reform program, over a 20-year time horizon, has been estimated at Rs 1.01 billion. In 2003 alone, the estimated savings are estimated at Rs 178 million.

Figure 4.9: Impact of Stalled Reform



Note: "out-of-state" refers to those emissions and damage costs as are estimated to arise in states that export electricity to Karnataka, such as those due to NTPC's Talcher project in Orissa.

Table 4.4: Economic Analysis—Stalled Reform

		NPV	2001	2002	2003	2004	2005	2006	2007	2008
BENEFITS										
grid supplied	[RsCr]	64209	6325	6860	7266	7822	8066	8134	8056	8487
self-generation	[RsCr]	5181	153	116	135	108	206	380	620	682
DSM	[RsCr]	0	0	0	0	0	0	0	0	0
exportable surplus (sales to PTC)	[RsCr]	0	0	0	0	0	0	0	0	0
total benefits	[RsCr]	69390	6479	6976	7401	7930	8272	8514	8675	9169
COSTS										
capital costs										
grid generation plants	[RsCr]	4996	769	1011	360	0	1188	719	775	0
..less salvage value	[RsCr]	-523								
pollution mitigation[FGD, etc]	[RsCr]	0								
T&D investments	[RsCr]	9018	411	1329	1641	2173	848	60	727	1509
self-generation plant	[RsCr]	3181	0	0	74	0	384	683	939	245
DSM investments	[RsCr]	0	0	0	0	0	0	0	0	0
renewable energy	[RsCr]	0	0	0	0	0	0	0	0	0
total capital costs	[RsCr]	16672	1179	2340	2074	2173	2420	1462	2441	1754
O&M costs										
spot purchases from PTC	[RsCr]	0	0	0	0	0	0	0	0	0
fuel	[RsCr]	10554	1032	1194	1306	1384	1412	1412	1294	1350
other non fuelO&M costs	[RsCr]	1015	69	95	115	126	135	140	144	148
G&A costs	[RsCr]	6728	653	816	793	788	802	831	860	890
other costs	[RsCr]	13538	3163	2846	2562	2306	2075	1868	1681	1513
fuel, self-gen plants	[RsCr]	2988	89	67	78	63	119	220	358	394
DSM[admin costs]	[RsCr]	0	0	0	0	0	0	0	0	0
DSM device O&M	[RsCr]	0	0	0	0	0	0	0	0	0
renewable energy	[RsCr]	0	0	0	0	0	0	0	0	0
total O&M	[RsCr]	34823	5004	5019	4853	4667	4543	4470	4336	4294
Environmental damage costs in Karnataka										
PM-10	[RsCr]	2801	66	70	82	89	119	168	231	270
SOx	[RsCr]	225	11	14	16	19	21	22	22	25
NOx	[RsCr]	2635	53	53	64	67	95	144	213	249
total environmental damage costs	[RsCr]	5661	130	137	162	175	235	334	466	544
consumptive water use	[RsCr]	820	103	103	110	110	110	110	110	110
Global:GHG 15 $/ton	[RsCr]	3172	297	339	369	396	408	412	383	404
total costs	[RsCr]	118303	6417	7598	7200	7124	7309	6377	7354	6702
net economic flows [production+local-e	[RsCr]	11755	62	-622	202	806	964	2137	1322	2466
net economic flows [production+local-e	[RsCr]	14927	358	-283	571	1202	1371	2549	1705	2870
net economic flows [production]	[RsCr]	18236	295	-382	474	1091	1309	2582	1898	3121
memo items										
served demand	[GWh]	206146	20774	22449	23685	25398	26081	26184	25816	27088
Economic cost of power [production co	[Rs/kWh]	2.50	2.98	3.28	2.92	2.69	2.67	2.27	2.63	2.23
incremental GWh served	[GWh]	49052		1675	2911	4624	5307	5410	5042	6313
incremental costs	[RsCr]	17381		2343	2190	2367	2642	1684	2663	2032
Average incremental cost (as proxy for	[Rs/kWh]	3.54								

Note: Under the stalled reform scenario we assume that T&D losses are not further reduced, but this is assumed to reduce only that part of the T&D investment that relates to loss reduction; some T&D investment for load growth and connection of new generating stations remains. Thus T&D investment in this table is Rs 90.15 billion (as NPV), compared to Rs 106.24 billion in the reform case—a reduction of Rs 16.09 billion.

5

Options

Introduction

5.1 In the short term, the financial difficulties faced by the power sector—and specifically the limitations on commercial escrow—mean that there are few choices open to it: whatever sources of generation are available will be eagerly accepted. As the sector becomes commercially viable in the longer term, the range of choice becomes greater. In this section we therefore examine the options that are available, given as perturbations of the baseline scenario.

Demand-Side Options

5.2 Despite the significant potential for DSM in Karnataka, there are surprisingly few studies. The measures that are relevant today are essentially those recommended in the Defendus study of 1995 (Reddy et al., 1995).[50] Little progress has been achieved since then.

Electrical Geyser Replacement

5.3 Almost every middle class household in Karnataka has one or more electrical geysers, usually incorporating a 2kW heater. There are some 1.4 million of these geysers in the state; typically operating 2 hours a day, they cause a morning peak that sometimes exceeds the evening peak (recall Figure 3.9). Solar water heaters, that would function reasonably well for 200–250 days a year, could in large part displace these geysers, although they would need backup for cloudy days. A solar system would need some planning for proper implementation, and in completed buildings the modification of plumbing could be difficult, but for new buildings it could be made mandatory. There is a discount of Rs 0.05/kWh up to a maximum of Rs 25/month for consumers with a solar system, and in 2002 it is estimated that some 6,000 solar water heaters were installed in Bangalore. This is only a very small fraction of the candidate households.

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[50] Energy for Sustainable Development Journal Volume II, No. 3, September/November 1995—*Integrated Energy Planning: Part I & II—The DEFENDUS methodology.* A. K.N. Reddy, A. D'Sa, G.D. Sumthra and P. Balachandra.

5.4 For the purpose of estimating the impacts of DSM the following factors have been considered:

- In the first year, 0.14 million solar water heater sets are proposed for installation, accounting for 10 percent of eligible total consumers. In subsequent years a growth of 5 percent is assumed.
- The new solar water heater, costing an estimated Rs 26,250, supplies 200 liters per day and has a useful life of 10 years. The conventional 2kW electric geyser, costing Rs 13,500, has a 50 liter capacity and a useful life of five years.
- Electric geysers are operational for 820 hours annually
- The option needs to be targeted for the urban pockets where there is the greatest concentration of all-electric homes (AEHs).

5.5 Figure 5.1 illustrates the DSM program analysis for this measure, and Figure 5.2 the economic analysis. The details of the other DSM measures described below are included in Annex I.

Figure 5.1: DSM Program Analysis—Electric Geyser Replacement

Programme implementation		residential:Solar/Gas geyser replacing electric geyser							
		2001	2002	2003	2004	2005	2006	2007	2008
unit savings,kWh	[kWh/y]	888							
savings achieved		1	1	1	1	1	1	1	1
unit savings,kWh/year	[kWh/y]	888.0	888	888	888	888	888	888	888
unit cost	[Rs/unit]	26250.0							
cost reduction		1.0	1	1	1	1	1	1	1
unit cost	[Rs/unit]	26250	26250	26250	26250	26250	26250	26250	26250
total	[#]	138956	145904	153199	160859	168902	177347	186215	195525
applicable fraction	[ ]	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70
eligible participants	[#]	97269	102133	107240	112602	118232	124143	130350	136868
participation rate	[ ]	0	0	0	0.1	0.2	0.4	0.6	0.75
participants	[#]				11260	23646	49657	78210	102651
new participants	[#]				11260	12386	26011	28553	24441
new device replacement	[#]	0	0	0	0	0	0	0	0
total new devices acquired	[#]			0	11260	12386	26011	28553	24441
before DSMprograme	[GWh]	119	125	132	138	145	153	160	168
consumption@old appliance	[GWh]	119	125	132	124	116	92	64	42
consumption@new appliance	[GWh]	0	0	0	0	0	0	0	0
energy with DSM programme	[GWh]	119	125	132	124	116	92	64	42
energy savings 3279	[GWh]	0.0	0.0	0.0	13.8	29.0	61.0	96.1	126.1
NPV 12.00%	[NPV]	694							

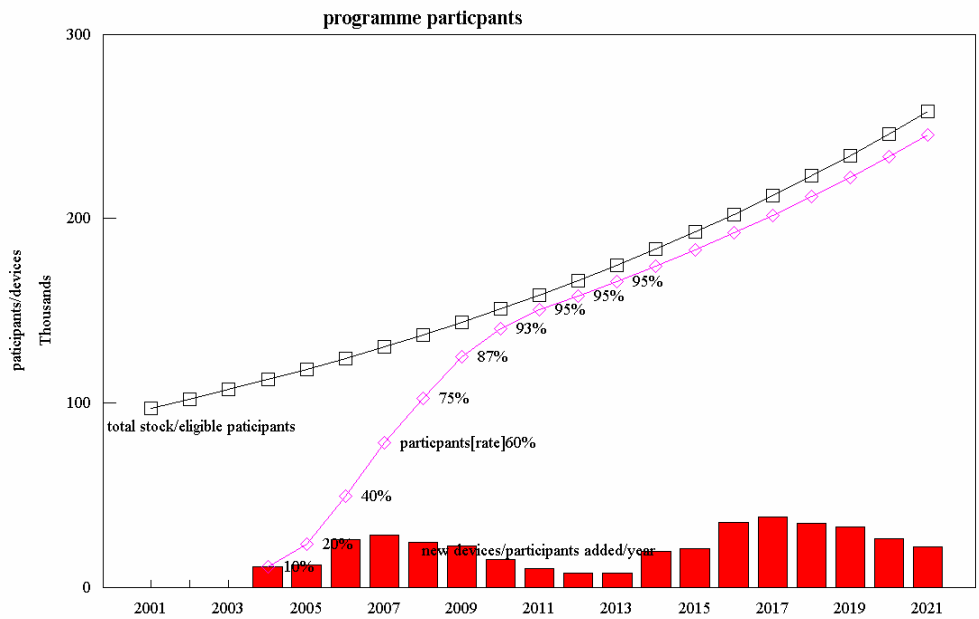
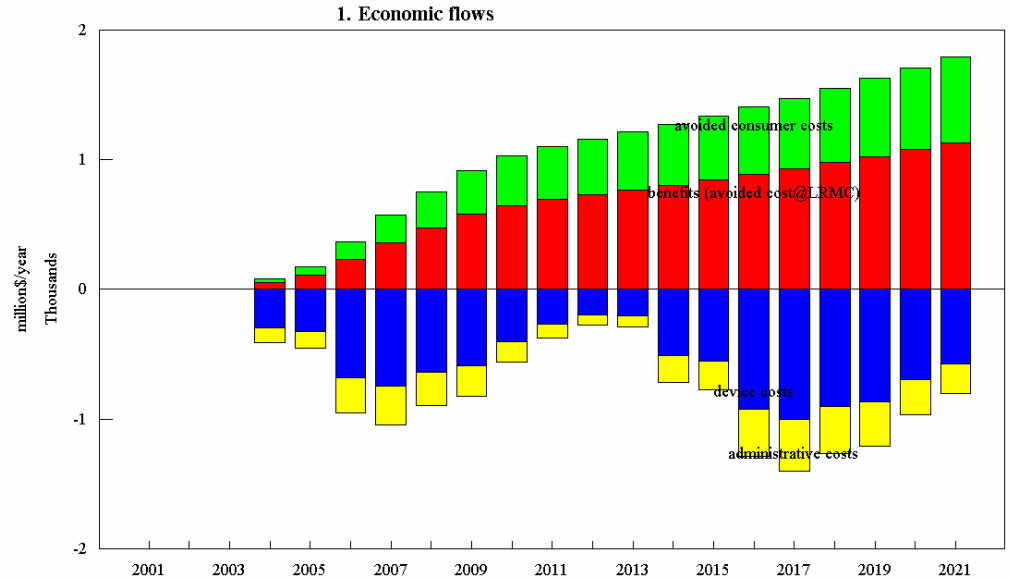


Figure 5.2: Economic Analysis of Geyser Replacement

Economic analysis			residential:Solar/Gas geyser replacing electric geyser							
			2001	2002	2003	2004	2005	2006	2007	2008
Cost of conserved energy (CCE)										
device costs		[RsMillion	0.00	0.00	0.00	295.58	325.14	682.79	749.51	641.57
operating costs		[RsMillion]								
administrative costs	40.00%	[RsMillion	0.00	0.00	0.00	118.23	130.05	273.11	299.81	256.63
consumer benefits		[RsMillion	0.00	0.00	0.00	-30.40	-63.85	-134.07	-211.17	-277.16
total costs		[RsMillion	0.00	0.00	0.00	383.41	391.35	821.83	838.15	621.04
NPV	12.00%	[RsMillion	2225.37							
CCE		[Rs/kWh]	3.207							
Economic Analysis										
assumed LRMC	3.750	[Rs/kWh]								
benefits (avoided cost@LRMC)		[RsMillion	0.00	0.00	0.00	51.87	108.94	228.76	360.30	472.90
avoided consumer costs		[RsMillion	0.00	0.00	0.00	30.40	63.85	134.07	211.17	277.16
device costs		[RsMillion	0.00	0.00	0.00	-295.58	-325.14	-682.79	-749.51	-641.57
administrative costs		[RsMillion	0.00	0.00	0.00	-118.23	-130.05	-273.11	-299.81	-256.63
operating costs		[RsMillion	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
total economic flows		[RsMillion	0.00	0.00	0.00	-331.53	-282.41	-593.06	-477.85	-148.14
NPV		[RsMillion	376.43							
ERR		[ ]	16.9%							
Cost of avoided Carbon										
kWh@consumer		[GWh]	0.00	0.00	0.00	13.83	29.05	61.00	96.08	126.11
applicable technical loss rate		[ ]	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
kWh@generation bus		[GWh]	0.00	0.00	0.00	16.27	34.18	71.77	113.04	148.36
net heatrate		[KCal/kWl	2425							
calorific value		[KCal/kg]	6300							
carbon content		[ ]	0.6							
carbon emissions		[Kg/kWh]	0.23							
		[1000t/y]	0.00	0.00	0.00	3.76	7.89	16.57	26.10	34.26
avoided emissions,discounted		[NPV]	188.48							
		[Rs/ton]	-1997							
		[$/ton]	-42							
avoided emissions,undiscounted		[1000t]	891							
		[Rs/ton]	-423							
		[$/ton]	-9							



Domestic Lighting

5.6 Domestic lighting is responsible for a large part of the evening peak. There is a significant potential for reducing this peak by the replacement of incandescent bulbs by compact fluorescent lamps (CFLs), and by the replacement of iron chokes in fluorescent tube-lights by electronic chokes. The main targets for these changes are:

- All-electric homes (1.4 million consumers)
- Homes with domestic electric lighting (5.3 million consumers)
- Bhagya Jyothi (1.7 million)

There is already significant use of fluorescent lighting in all-electric homes, but in the other two categories incandescent bulbs are heavily predominant.

5.7 The following assumptions are made for a DSM program designed to increase the use of CFLs and replace iron chokes:

- 1,460 annual lighting hours.
- 60W incandescent bulbs, priced at Rs 10 each, to be replaced by 15W CFLs costing Rs 250.
- The life of an incandescent bulb is six months; the working life of a CFL is five years.
- 40W fluorescent tube-light set with iron choke costing Rs 120 consumes 55W; the same tube-light with electronic choke consumes 40W and costs Rs 200.
- The life of electronic choke is estimated to be five years, compared to two years for an iron choke.

Commercial Lighting

5.8 Fluorescent lighting already has a significant penetration in commercial lighting applications, notably in offices and shops, but there are many commercial enterprises, such as hotels, where there is potential for the expanded use of CFLs. The replacement of iron chokes by electronic chokes, however, has very large potential. We make the following assumptions for the commercial sector DSM program:

- Annual lighting hours are estimated to be 2,260.
- 60W incandescent bulbs costing Rs 10 are replaced by 15W CFLs costing Rs 250.
- The life of an incandescent bulb is considered to be six months and the life of a CFL, five years.

- A 40W fluorescent tube-light set with iron choke consumes 55W and costs Rs 120; the same tube-light with electronic choke consumes 40W and costs Rs 200.
- The life of an electronic choke is estimated to be five years, compared to two years for an iron choke.

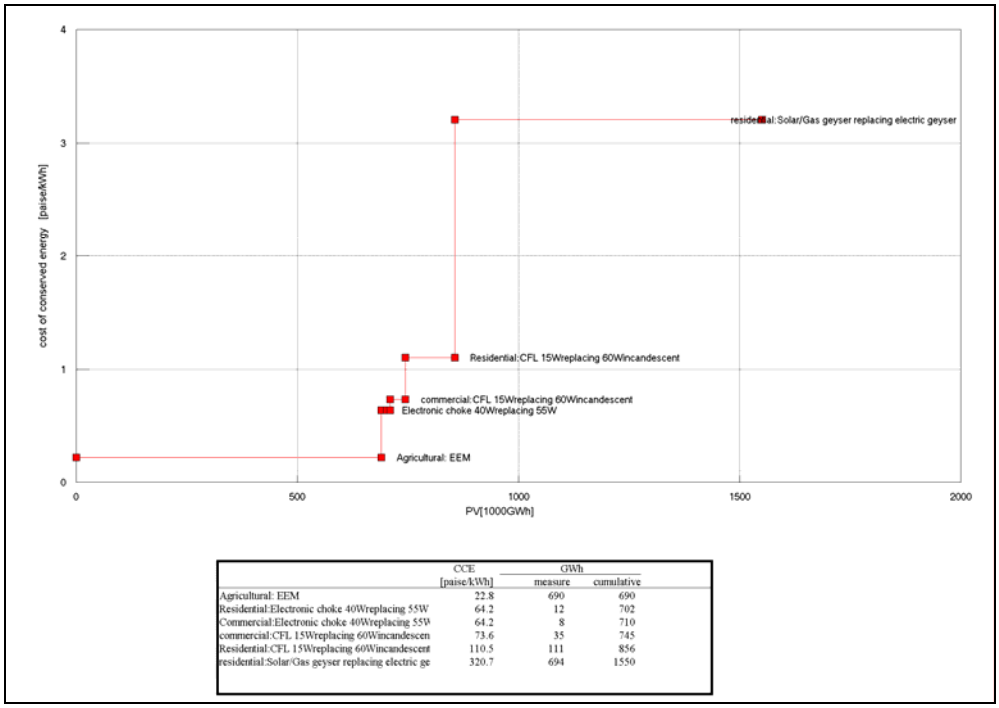
Distribution Losses in the Rural Area and Agricultural Pump-Set Consumption

5.9 In most of the agriculturally oriented rural distribution networks, line losses are of the order of 30 percent. These can be reduced to 6 percent in an economically attractive manner by raising the voltage of the distribution system: under the so-called High Voltage Distribution System (HVDS), an 11kV line is extended to very near to the end user and final distribution made via small transformers supplying a few consumers. This both brings the end user voltage to within acceptable limits and permits operation of energy-efficient pumps. Existing pumps have an efficiency of only about 20–22 percent; the new pumps are 40–42 percent efficient in practice and in theory are up to 48 percent efficient. State-wide implementation of this option would halve agricultural electricity consumption. We make the following assumptions for the DSM program:

- Initially, 5 percent of pump-sets are considered for replacement and conversion to HVDS.
- Existing pump-sets are considered to have an average rating of 5.39kW (7 horsepower (HP)). The replacement energy-efficient pump is rated 2 kW (3HP).
- 1,800 annual operating hours.
- The average life of an existing pump is considered to be five years and that of a new pump, 12 years.
- The cost of existing pump-sets is estimated at Rs 10,000 and new pump-sets at Rs 30,000 (inclusive of all pipelines, groundwork, and so forth).
- The cost of implementing HVDS is estimated as Rs 40,000 per pump-set.
- The total estimated savings are thus Rs 16,000 per pump-set per year, for a simple payback time of 4.3 years.

5.10 Figure 5.3 summarizes these various DSM measures in the form of a supply curve for DSM, plotting potential energy supplied versus the cost of conserved energy (based on an exogenous estimate of the LRMC of supply).

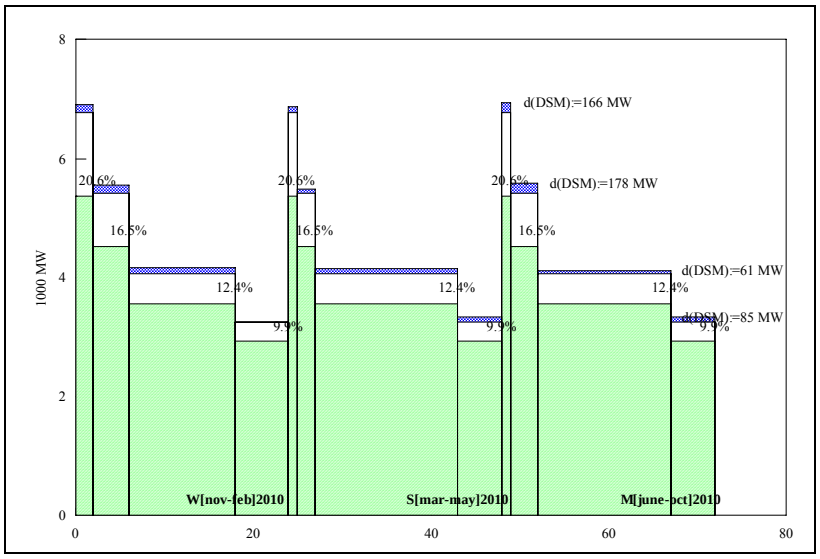
Figure 5.3: DSM Supply Curve (Cost of Conserved Energy versus GWh)



	CCE [paise/kWh]	GWh measure	GWh cumulative
Agricultural: EEM	22.8	690	690
Residential:Electronic choke 40Wreplacing 55W	64.2	12	702
Commercial:Electronic choke 40Wreplacing 55W	64.2	8	710
commercial:CFL 15Wreplacing 60Wincandescen	73.6	35	745
Residential:CFL 15Wreplacing 60Wincandescent	110.5	111	856
residential:Solar/Gas geyser replacing electric ge	320.7	694	1550

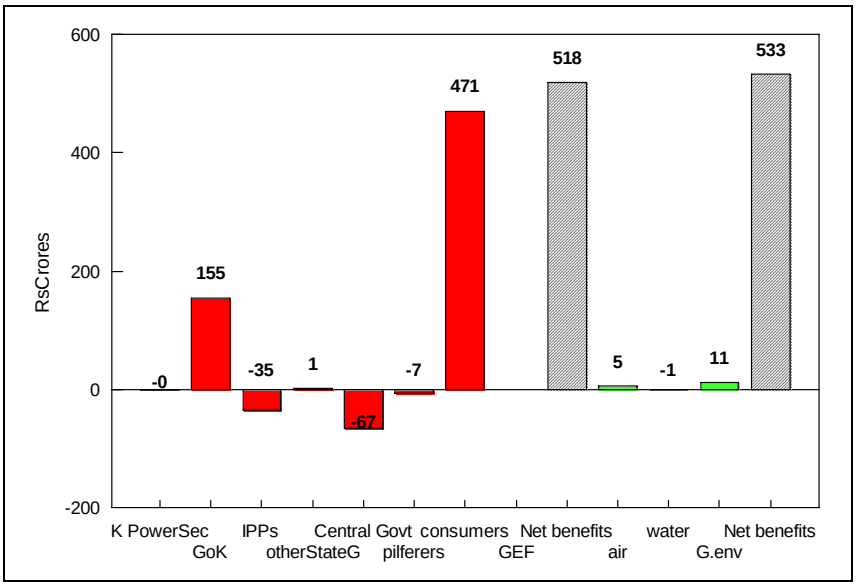
5.11 Figure 5.4 shows the resulting impact of the entire set of DSM measures on the 2010 load curves. The reduction on the peak is 166MW, compared to only 85MW in the off-peak period.

Figure 5.4: Impact of DSM on the Load Curve (in 2010)



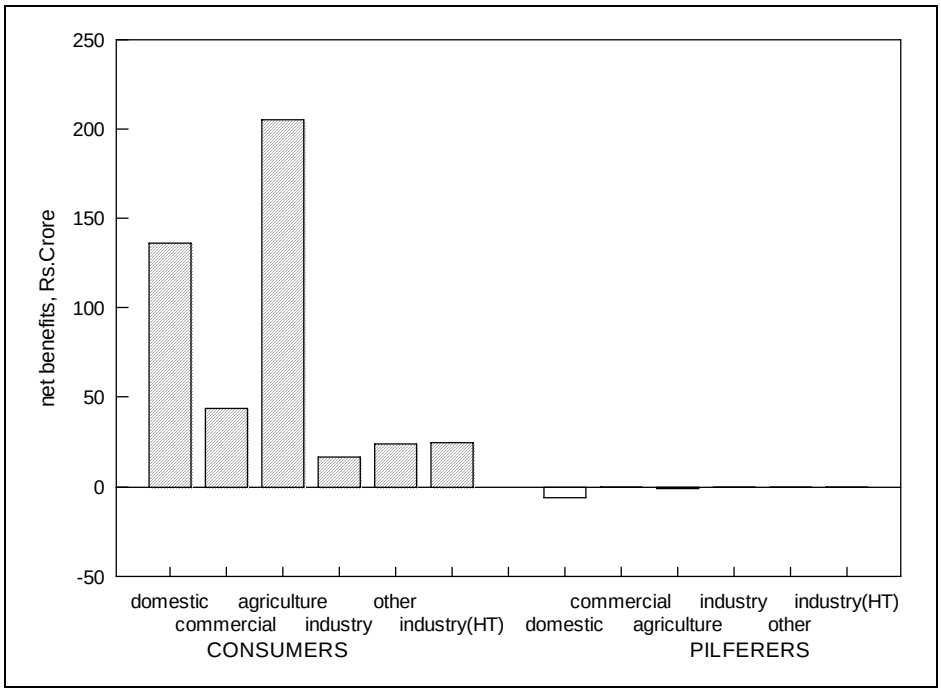
5.12 As shown in Figure 5.5, DSM is a classic win-win option, producing benefits of Rs 5.18 billion, rising to Rs 5.33 billion when environmental externalities are taken into account. The marginal deterioration in water consumption is a peak shaving effect, which makes the plant load factor (PLF) at base load plants slightly higher and hence also steam cycle generation and consumptive water use in Karnataka slightly higher.

Figure 5.5: Distribution of Costs and Benefits—DSM



5.13 Because the DSM is in the subsidized sectors (domestic, agriculture), every kWh that is not sold to these sectors brings financial benefit to the power sector. As losses decline, all else being equal the tariff for everyone would also decline — with the result that even HT industry would benefit.

Figure 5.6: Distribution of DSM Benefits among Consumer Groups



5.14 There are opportunities for DSM in other sectors also, notably industry. These were discussed in detail in an EIPS special study (EEEC 1997). However, these opportunities are not considered to be appropriate immediate targets of state government policy because of their negative short-term impact on the finances of the power sector. The short- to medium-term priority is clearly to implement DSM in the subsidized sectors, which is where the win-win opportunities currently reside. Industrial DSM opportunities would be more appropriately managed through the use of tariff signals, with implementation left to the sector itself.

Supply-Side Options

Nuclear

5.15 Nuclear power is a controversial generation option. From the standpoint of economic efficiency, the key question is whether or not the tariffs charged by the Nuclear Power Corporation (NPC) reflect actual economic costs, including the potential costs of eventual decommissioning, and the degree to which nuclear fuels are subsidized by the GoI. Putting aside the controversy over nuclear safety and the safe disposal of spent fuel, there are environmental advantages to nuclear generation: notably the avoidance of GHG emission associated with coal generation and the absence of damage costs associated with local air pollutants. Karnataka has a 54MW share of the 2 x 220MW Kaiga nuclear plant that is located in the North Canara district, near Karwar. Kaiga has recently experienced some operational problems, resulting in lower than expected generation.

5.16 Karnataka has no direct influence over the quantum of nuclear power that is potentially available to it, since the investment program of NPC is determined at the center. India's nuclear power program is summarized in Table 5.1. Which of the proposed plants will actually materialize, given the resource constraints faced by NPC, is unclear. If the four additional units at Kaiga were to be built and commissioned, for example in 2012–2013, Karnataka would be allocated a share that we take here to be 220MW. In addition, Karnataka could expect to receive shares of the Kudankulam and Kalpakkam projects, which we assume would be a further 220MW in 2014–2015.

Table 5.1: India's Nuclear Power Program

	Existing	Under construction	Proposed
TAPP	2 x 160		2 x 500
RAPP	2 x 220	2 x 220	
NAPP	2 x 220		
Kalpakkam (Tamil Nadu)	2 x 170		
Kankarpara	2 x 220		2 x 220
Kaiga (Karnataka)		2 x 220	4 x 220
Jaitapur (Maharashtra)			2 x 500
PFBR (Kalpakkam)			1 x 500
Kudankulam (Kerala)			2 x 1000
New plant in Punjab/Uttar Pradesh			2 x 500
Total	1980 MW	880 MW	6820 MW

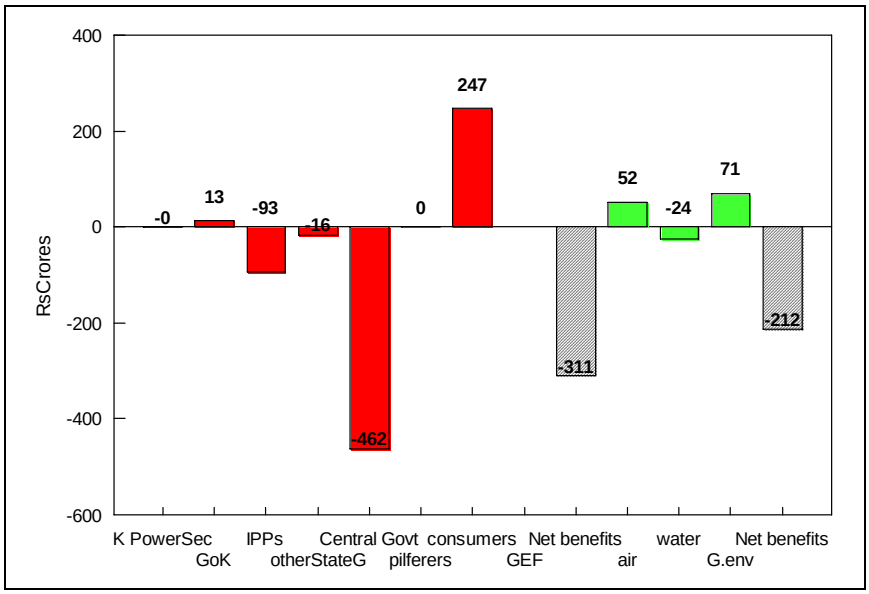
Source: *CEA (1999)*

5.17 The economic costs of nuclear power in India are difficult to establish. The CEA normative value of Rs 57 million/MW for the financial cost, including interest during construction (IDC), seems low compared to the corresponding CEA normative figure for a 500MW coal unit of Rs 44 million/MW—especially given that the gestation period for a nuclear plant is at least two years longer than that of a coal plant. For the purposes of this study we take the economic cost of nuclear to be Rs 80 million/MW.

5.18 As shown in Figure 5.7, nuclear power has the expected beneficial impacts on GHG and local air emissions. Whether or not these advantages offset the environmental concerns regarding radioactive waste disposal are debatable, notwithstanding that our capital cost estimates expressly include the costs of decommissioning (as the PV of the decommissioning cost at the end of a plant's economic life).

5.19 While nuclear power, producing a net economic loss of Rs 3.11 billion, thus is not economic, Karnataka's consumers would benefit, since the economic loss is covered by the subsidy from the center. GHG emissions also decline, with a cost of avoided carbon of US$10/ton.

Figure 5.7: Impacts of Nuclear, Relative to Base Case



Coal Washing

5.20 Raichur uses only unwashed coal from the Singareni, Mahanadi, and Western coalfields, but is soon to use also washed coal with a GCV of 4,300kCal/kg and ash content of 32 percent (see Table 5.2). This washed coal is to be supplied under a build–own–operate (BOO) contract with a private company that is building washeries at the Western coalfields and at Singareni.

Table 5.2: Washed Coal

	Singareni	Western Coalfields
FOB washery	1,469	1,327
Railway freight	416	518
Rs/ton	1,885	1,845
GCV	4,300	4,300
Rs/MCal	0.43	0.43
Comparison with unwashed coal	Singareni, G grade	WCL, G grade
Delivered cost, Rs/ton	1,095	1,125
GCV	3,500	3,500
Rs/MCal	0.32	0.31

LNG

5.21 As noted in the introduction, the economics of using liquefied natural gas (LNG) for power generation in India are being questioned as a result of the Dabhol fiasco. Most of the problems are a consequence of the lack of transparency in the tariff, the general mismanagement of the project, and the high return on equity originally sought by the IPP. In practice, combined-cycle power generation is one of the most cost-effective options for thermal power generation, as evidenced by the many gas-fired IPPs that are successfully (and economically) operating in AP and Gujarat. Most importantly, from an environmental perspective, the air emissions per kWh are low, supporting both local and global environmental goals.

5.22 For the LNG option we assume that a 2,200MW facility would be come on line in a west coast location in 2010. The generation cost is assumed to be that of CCCT; gas costs are based on Btu equivalence with crude oil, plus US$0.05/MBtu as the assumed regasification cost.

Imported Coal

5.23 Karnataka's distance from the major coal export ports of Orissa means that the economically least-cost fuel for Karnataka's coastal locations is imported rather than domestic coal. Because of the policy of the GoI to protect Coal India Ltd with high customs duties, the financially most cost-effective fuel at these locations would however be domestic coal, as assumed in the base case expansion plan.

5.24 The least-cost solution nonetheless shows also the use of imported coal at these coastal locations. This is to expose the impact of the customs duty policy of the GoI (and therefore the result of making the decision based on financial rather than economic costs).

HVDC

5.25 Studies conducted by CEA suggest that mine-mouth generation in the eastern states, with HVDC power transmission to south and north India, should comprise part of the national least-cost power scenario in the long term. The first stage of this national strategy is now being implemented. NTPC's Talcher II 2,000MW project is to be commissioned under the following schedule:

- Unit 1: 500MW in March 2003
- Unit 2: 500MW during 2004
- Unit 3: 500MW during 2005
- Unit 4: 500MW during 2006

A new HVDC line from Talcher in Orissa to Kolar in Karnataka is now under construction by Power Grid Corporation Limited, and its output will be distributed to the south Indian states of Karnataka, Tamil Nadu, Pondicherry, Kerala, and Andhra Pradesh. Karnataka's share of distribution is 464MW.

5.26 Given the extensive reserves of the Talcher coalfields and the high costs of rail/coastal shipment, it seems reasonable to hypothesize a Talcher III and Talcher IV, for

which Karnataka's share would again be, say, 500MW for each project. Box 1 shows the calculation of the economic cost of HVDC transmission at this large scale of power transfer.

Box 1: HVDC Transmission Costs

Assumptions

installed capacity	MW	2000
PLF	[ ]	0.75
	GWh/year	13140
transmisison loss	[ ]	5%
delivered GWh/year	[GWh]	12483
discount rate	[ ]	0.12
life	years	20

Cost comparison

	NPV	-2	-1	0	1	2	3	4	5	6	7
capital costs HVDC	3199	1000	2000	1000							
O&M costs @1.5%	319				60	60	60	60	60	60	60
total HVDC link	3518	1000	2000	1000	60	60	60	60	60	60	60
GWh	66367				12483	12483	12483	12483	12483	12483	12483
Rs/kWh [economic]	0.053										

excerpt only: calculations done for 20 year time period

Mini Hydro

5.27 Karnataka has vast potential for small hydro projects, at medium-sized and minor irrigation dams, canal drops, and hill streams. The Government of Karnataka is encouraging private sector participation in small hydropower projects: state water royalties are waived for small hydro projects of less than 20MW capacity.

Table 5.3: Present Status of Small Hydro

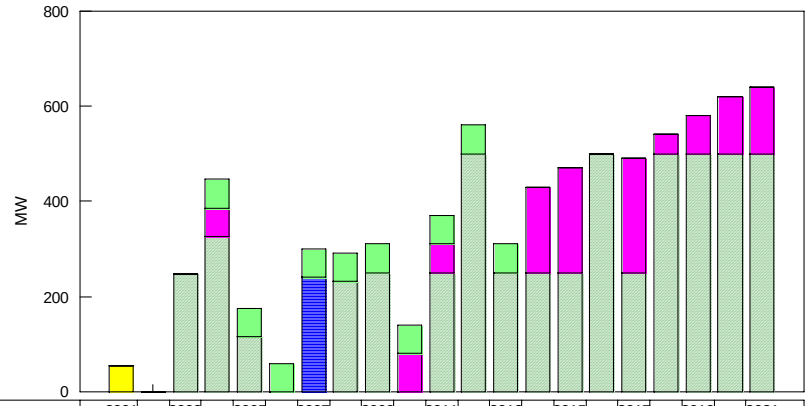
	number	MW
Allotted by GoK (1)	156	755
Commissioned	29	143.7

(1) GoK has given a license to an entity for a particular site, stipulating implementation within five years.

5.28 For the small hydro scenario we assume that the remaining 600MW[51] of allotted projects would be built over a 10-year period, commencing 2005, as depicted in Figure 5.8.

[51] i.e. the balance of the allocated projects in Table 5.4 (755 MW less 143MW already commissioned).

Figure 5.8: Expansion Plan for Small Hydro



	2001		2003		2005		2007		2009		2011		2013		2015		2017		2019		2021
hydro	0	0	0	0	0	0	240	0	0	0	0	0	0	0	0	0	0	0	0	0	0
coal	0	0	248	326	116	0	0	232	250	0	250	500	250	250	250	500	250	500	500	500	500
gas/lng	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
nuclear	54	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LQ	0	0	0	60	0	0	0	0	0	80	60	0	0	180	220	0	240	40	80	120	140
renewables	0	0	0	60	60	60	60	60	60	60	60	60	60	0	0	0	0	0	0	0	0

Wind

5.29 Tamil Nadu and Gujarat account for most of the 1,080MW installed wind capacity in India. Karnataka has only 28MW installed (Table 5.4). According to the latest annual report of the Department of Nonconventional Energy Sources (DNES), Karnataka nonetheless has the second highest gross potential in the country for wind generation, with a technical potential of more than 1,000MW (a figure that is based on a maximum penetration of wind energy of 20 percent of the relevant grid).

Table 5.4: Installed Capacity, MW Wind Generation

	As of 31 December 1999	As of 31 December 2001	Gross potential	Technical potential
AP	68	92	8275	1550
Gujarat	167	167	9675	1750
Karnataka	28	54.8	6620	1025
Kerala	2	2	875	605
MP	21	22.6	5500	1200
Maharashtra	33	320	3650	2990
Rajasthan	2	14	5400	885
Tamil Nadu	758	832	3050	1700
Orissa			1700	680
Others	2	3	450	450
Total	1080	1507	45,195	12835

Source: *DNES (2002).*

5.30 A summary of current wind power projects is provided by Karnataka Renewable Energy Development Limited (KREDL), the nodal agency for renewable energy projects in the state (Table 5.5).

Table 5.5: Wind Power Projects in Karnataka

Potential (MW)	Projects allotted by government		Projects commissioned	
	No.	MW	No.	MW
7000	89	1,169	24	79.82

5.31 When capacity penalties are properly assessed and accounted, wind power is not yet economic. Current costs stand at around US$1,000/kW (Rs 48 million/MW) (see Table 5.6).

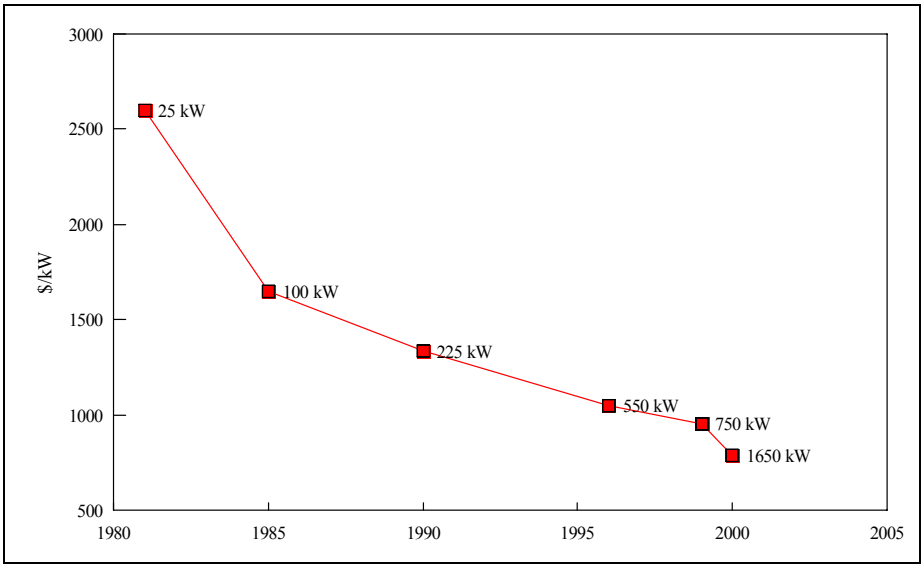
Table 5.6: International Price Comparisons for Wind Power

	US$/kW	Basis/breakdown
China, present cost (3)	$1,028	Equipment cost 6,000 Yuan/kW; site costs 2,500 kW/kW
China, 2010 estimate (3)	$785	Equipment cost 4,000 kW/kW; site costs 2,500 kW/kW
Croatia, Ravne 5.6MW	$991	Of which, equipment US$749/kW; 750kW machines
Germany, 2001 actual	$1,072	Average of 11 German wind farms with start-up dates in 2001 (1)
USA, 2001–2002, actual	$1,100	Average cost of three wind farms totaling 350MW in Texas and Pennsylvania (2)

Sources:
(1) Wiesenthal, Meier, and Milborrow (2001).
(2) As reported in Renewable Energy World (2003)
(3) World Bank (2003).

5.32 Wind power costs are declining as scale economies lower the costs of turbine-generators. Unit costs are expected to decrease between 10 and 15 percent for every doubling of worldwide installed capacity, and present costs of around US$750/kW (for the turbine-generator) are expected to decline to at least US$500/kW over the next decade. The current total installed cost of Rs 48 million/MW (US$1,000/kW) can be expected to decline to Rs 36 million/MW by 2010, and to Rs 32 million/MW by 2015 (Figure 5.9).

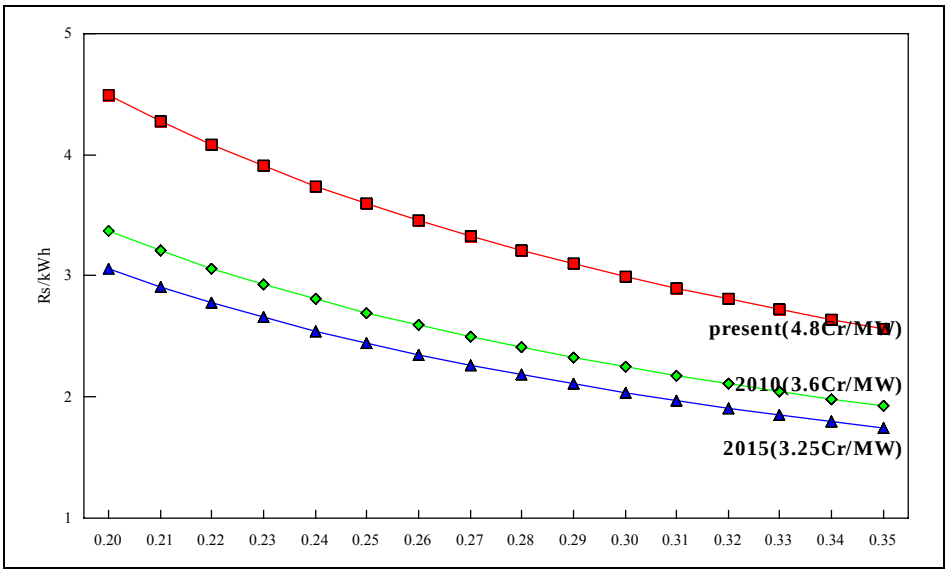
Figure 5.9: Wind Power Cost Trends



Source: *GE Wind Power*

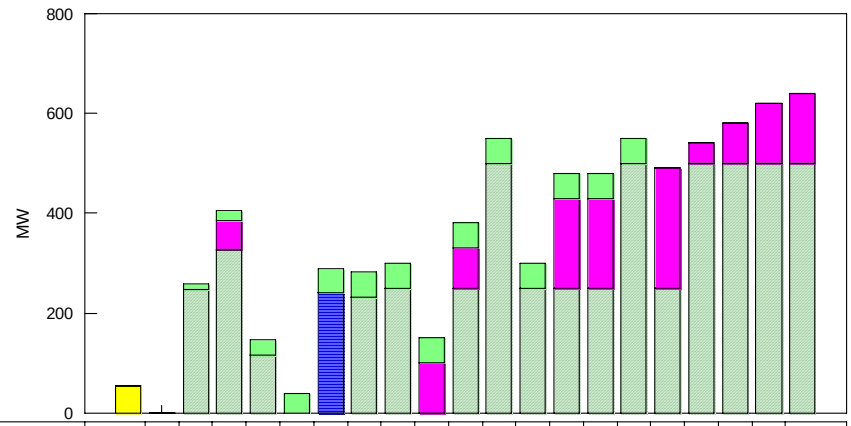
5.33 The economics of wind power in Karnataka is determined by the existence of sites with good capacity factors (see Figure 5.10).

Figure 5.10: Wind Power Costs as a Function of Annual Capacity Factor



5.34 The wind power scenario envisioned by this study is based on the assumption that 50 percent of the 1,200MW currently allotted by the GoK would be implemented over a 10-year period, at costs starting in 2004 at Rs 46 million/MW (US$970/kW) and falling by 2014 to 3.2 Rs million/MW (US$670/kW). The resulting capacity expansion plan is shown in Figure 5.11.[52]

Figure 5.11: Wind Scenario Expansion Plan



	2001		2003		2005		2007		2009		2011		2013		2015		2017		2019		2021
hydro	0	0	0	0	0	0	240	0	0	0	0	0	0	0	0	0	0	0	0	0	0
coal	0	0	248	326	116	0	0	232	250	0	250	500	250	250	250	500	250	500	500	500	500
gas/lng	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
nuclear	54	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LQ	0	0	0	60	0	0	0	0	0	100	80	0	0	180	180	0	240	40	80	120	140
renewables	0	0	10	20	30	40	50	50	50	50	50	50	50	50	50	50	0	0	0	0	0

5.35 The tariff granted to renewable energy producers is a major concern. Over the past decade prices have been set under a 1994 MNES notification of the Ministry of Nonconventional Energy Sources (MNES) that set the tariff at Rs 2.25/kWh, with a 5 percent annual escalation. The tariff in 2003 is Rs 3.49/kWh, which is regarded as unsustainable by KPTCL, which as a result is negotiating with the developers for a lower

[52] Scenarios with much greater quantities of wind power are of course possible, but are likely to be problematic. Most studies that claim high penetration of wind power are subject to a number of practical, technical, and economic doubts. For example, a German study asserts Europe could provide up to 20 percent of its total base load energy from wind, using HVDC importation from North Africa (Giebel, Czisch, and Mortenson 2002). "Wind Force 12" (European Wind Energy Association and Greenpeace, 2003) outlines a scenario in which wind would meet 12 percent of the world's electricity needs by 2020, with 60,000MW generated in India. This total is 33 percent higher than the DNES estimate of India's gross potential and would imply for Karnataka an unrealistic installed capacity of some 10,000MW. For these reasons we have elected to assess wind power for Karnataka by using the more reasonable scenario of 600MW over the next 10 years.

base price and lower annual escalation (reported to be 2 percent, which in real terms implies a price decrease).[53]

Bagasse Cogeneration

5.36 Bagasse is a waste product of sugar making. Karnataka has about 45 sugar plants. In 2002 KPTCL purchased 314.5GWh from eight plants that have cogeneration facilities (Table 5.7), accounting for 1.1 percent of the total energy available in the state.[54]

Table 5.7: Sugar-Cogeneration Plants in Karnataka

Plant	Capacity (MW)	Generation GWh
Ugar Sugar	32	69.9
Shamnur Sugars	19.5	100.02
Renuka Sugars	22.5	34.61
Bannari Amman Sugars	11	57.71
ICL Sugars	7.5	13.54
Prabhulingeshwar Sugars	11	33.66
Dandeli Fero Ltd	1.5	4.45
Jamakhandi Sugars	6	0.62

5.37 As indicated in Table 5.8, cogeneration is envisaged at 63 projects, supplying some 530MW to the grid.[55]

Table 5.8: Planned Bagasse Projects

Sector	Number of companies	Crushing capacity (TCD)	Installed capacity (MW)	Exportable capacity (MW)
Private	29	90,250	550	382
Public	2	7,500	34	18
Cooperative	15	38,250	210.1	131
Total			794	532

TCD=tons per calendar day

[53] The prices for other renewable energy forms are also being renegotiated.

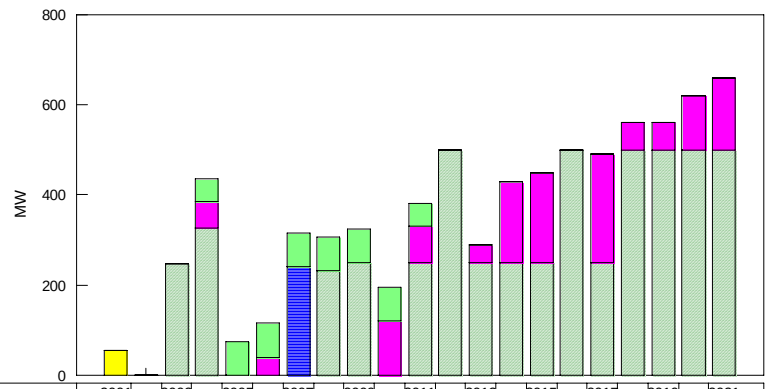
[54] Among other forms of biomass-based electricity there are some promising opportunities for biodiesel fuels, such as those based on *pongamia pinnata* and *jatroppha curcas*. The main role for such fuels would be in rural areas that lack access to electricity—diesel generation for grid-connected applications is rarely least-cost.

[55] A new technology for bagasse gasification is under development that would double power output, with the gas powering a CCCT generator. A demonstration in Brazil is underway that, if successful and leading to commercialization, would double the sugar cane cogeneration potential of Karnataka.

5.38 Sugar cogeneration power plants have capital costs of Rs 30–35 million/MW. Most bagasse cogeneration plants operate only during the sugar season, between September and March/April. A USAID project, however, has successfully demonstrated that it is feasible to store sugar cane waste and to extend the season to 10 months from the current seven or eight months (EEEC, 2001).

5.39 The bagasse scenario assumes that the 550MW of bagasse generation projects identified in Table 5.8 would be built between 2004 and 2011, with the resulting capacity expansion plan as shown in Figure 5.12.

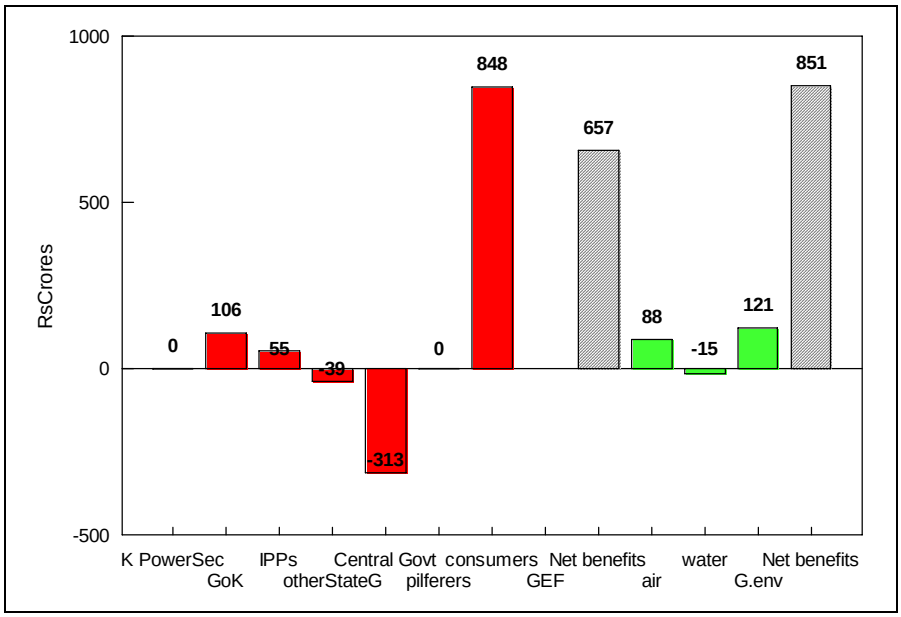
Figure 5.12: Bagasse Option Capacity Expansion Plan



	2001		2003		2005		2007		2009		2011		2013		2015		2017		2019		2021
hydro	0	0	0	0	0	0	240	0	0	0	0	0	0	0	0	0	0	0	0	0	0
coal	0	0	248	326	0	0	0	232	250	0	250	500	250	250	250	500	250	500	500	500	500
gas/lng	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
nuclear	54	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LQ	0	0	0	60	0	40	0	0	0	120	80	0	40	180	200	0	240	60	60	120	160
renewables	0	0	0	50	75	75	75	75	75	75	50	0	0	0	0	0	0	0	0	0	0

5.40 Bagasse is a classic win-win option. Under this scenario, net economic benefits before the consideration of externalities are Rs 6.57 billion, increasing to Rs 8.51 billion when the avoided environmental damage costs are taken into consideration. Returns to the sugar industry increase by Rs 1.66 billion; offset by the returns to conventional fossil fuel IPPs, they produce a net gain to IPPs of Rs 0.55 billion.

Figure 5.13: Impacts of Bagasse Utilization



5.41 The gain to consumptive water use is that related to a diminution of thermal fossil generation. The sugar industry is highly water-intensive (and is the cause of some serious concerns in the Krishna basin), and the economics of bagasse projects benefit from a water price that is far below the opportunity cost. Given that bagasse projects are already in place, however, advantage should be taken of the power that they cogenerate. The water consumption of the bagasse project itself is a sunk cost that is not relevant if we draw the boundaries of analysis around the power sector.[56]

Krishna River Hydro

5.42 Given the environmental concerns of building hydro projects in the Western Ghats, the baseline capacity scenario envisages no additional large hydro projects beyond those already under implementation, including the 290MW Almatti Dam project.[57] Absent the planned power storage at the Upper Krishna Power Project

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[56] If water resource planning were to occur on a basin-wide basis, considering all of the tradeoffs between water supply, thermal and hydro power generation, irrigation and optimal cropping patterns, and all inputs were priced at their opportunity costs, bagasse would unlikely assume the share of total consumptive water use in the Krishna basin as it does presently. Given the present state of inter-state water dispute, basin-wide water resource planning in the Krishna and Cauvery may be decades away; nevertheless, there are very large opportunity costs associated with the present utilization pattern.

[57] The first 15MW turbine is scheduled to be commissioned in early 2004. Because of the limitation of the dam's operating height to 519.6 meters, the Almatti units will not generate at their rated capacity (the penstocks, in place for almost a decade, were sized for the original 524.2 meter operating height). The capital costs are reported by KPCL at Rs 6.74 billion, equivalent to Rs 24 million per MW. These

(UKPP)—a consequence of the Supreme Court ruling that limits the operating height of the Almatti dam to 519.6 meters—the energy and capacity of the UKPP is severely limited and the economics unfavorable.

5.43 There can be no question that if the resources of the Krishna River were planned to optimize the entire water utilization in the basin, rather than to meet individual state interests, the operating height of the Almatti dam would be 524.6 meters. It has in fact been built to this height. As was pointed out in Karnataka's submissions to the Supreme Court, the planned power storage at Almatti would benefit not just Karnataka, but also Andhra Pradesh, because it effectively would increase the storage capacity available to AP. (In effect, it would be equivalent to increasing the storage of AP's Srisailam reservoir, but with the evaporation loss going to the account of Karnataka's share of allocated Krishna waters.) This power storage not only would permit the construction of a cascade of run-of-river plants below the Naraynpur reservoir (the so-called Tammankal project),[58] but also would make economic the Jurala project on the Karnataka–AP border.

5.44 If a Krishna River Basin Commission, on the model of the Tennessee Valley Authority (TVA) or the Indian Damodar Valley Authority (DVA), were to be created, there is significant hydro capacity that it could make available:

- The energy output of the Almatti powerhouse would increase from 320GWh/year to 640GWh/year. Since the Almatti dam has already been constructed for operation at 524 meters, only the gates, which are designed for operation to 519.6 meters, would need replacement. Operating capacity would increase from 240MW to 290MW, for which the capital cost may be taken at Rs 2 million/incremental MW.
- The 810MW Tammankal cascade would become feasible, the power output of which we may assume would be assigned two-thirds to Karnataka and one-third to AP (under the hypothesized scenario in which AP agrees to the basin-wide optimization).[59]
- The cost of the Tammankal cascade is estimated at Rs 20.6 billion (or Rs 25 million/MW).[60]

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exclude the costs of dam construction and resettlement and relocation, which are sunk costs already spent by the Irrigation Department.

[58] The National Hydro Power Corporation (NHPC) is reported to have expressed an interest in taking up the Tammankal scheme, but absent the planned power storage at Almatti this project is not economic, because significant flows would be released from Naraynpur only during the monsoon season. There would be little generation in the dry season.

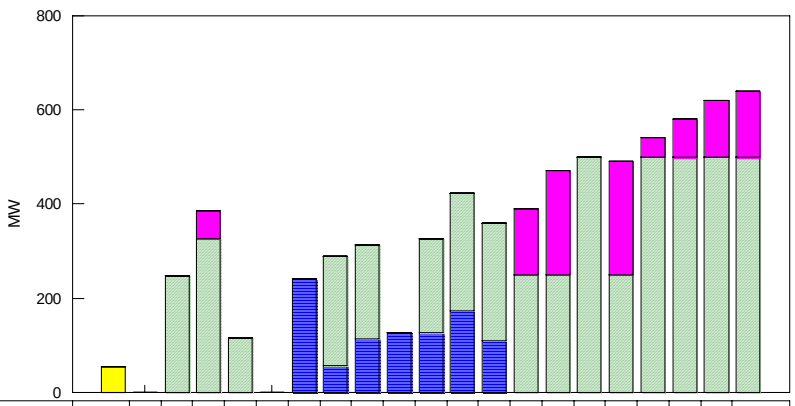
[59] The cascade powerhouses may be taken as 170MW, 190MW, 190MW, and 260MW. The assumed Karnataka shares are 113MW, 127MW, 127MW, and 173MW.

[60] Estimates from Chamundi Power Corporation, Upper Krishna Power Project, Application to CEA for "In-Principle Clearance", December 1995. The costs are relatively low because only small weirs are

- The 221MW Jurala power project would become feasible, the power benefits of which we assume would be divided equally between Karnataka and AP.[61]

5.45 The corresponding capacity expansion plan is shown in Figure 5.14 The hydro scheme displaces coal and some thermal peaking capacity. The displacement of thermal generation results in significant decreases in all of the thermal-plant-related environmental attributes, and is also less costly, with a net increase in economic benefits (as NPV in constant 2002 rupees) of Rs 3.5 billion.

Figure 5.14: The Krishna Hydro Scenario—Expansion Plan



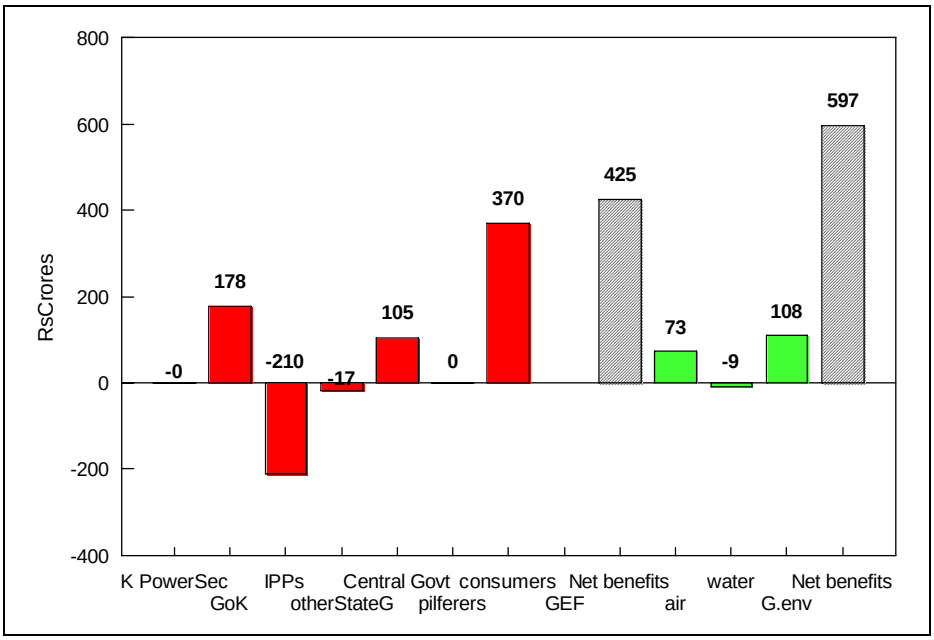
	331		331		331		331		331		331		331		331		331		331		331
hydro	0	0	0	0	0	0	240	57	113	127	127	173	110	0	0	0	0	0	0	0	0
coal	0	0	248	326	116	0	0	232	200	0	200	250	250	250	250	500	250	500	500	500	500
gas/lng	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
nuclear	54	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LQ	0	0	0	60	0	0	0	0	0	0	0	0	0	140	220	0	240	40	80	120	140
renewables	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

5.46 These results do not generalize to other hydro projects—particularly not to those in the Western Ghats. The Upper Krishna hydro projects are unique in that the main environmental and social impacts associated with the Almatti and Naraynpur dams are sunk (because the dams are built), and hence excluded from this analysis. Bagalkot, the major town in the project area, must be completely relocated to achieve even the reduced 519.6 meter operating height.

required for these plants, since the storage is provided upstream at the Naraynpur and Almatti reservoirs.

61 APSEB (1992). The original estimate was Rs 3.69 billion, which we have updated to Rs 6.00 billion, or Rs 27 million/MW (this is consistent with reported costs for the powerhouse at Almatti).

Figure 5.15: Impact of the Krishna Hydro Project



Box 2: Options Not Examined

Several options considered in other EIPS case studies are not included in this study of Karnataka. The reasons are as follows:

Hydro imports from Nepal (or the northeastern states)
With the establishment of the PTC and the full synchronization of the regional grids (which currently are connected only by asynchronous links) scheduled for completion by 2010, should any large-scale hydro projects come to fruition in Nepal it is conceivable that some of the power produced might be marketed by PTC in south India. There are also plans for large-scale HVDC transfers to the Delhi area from hydro projects in India's northeastern states (a distance of about 70 percent of that from Nepal to south India). The realization of such schemes is unlikely in the immediate future, however, and they therefore are not considered in this study of Karnataka.

Thermal plant rehabilitation
Karnataka has only one major thermal complex, at Raichur. As this is a comparatively new power plant (the first unit was commissioned in 1985 and the seventh unit in 2002), there will be no rehabilitation projects in the near future.

Solar thermal
Karnataka's climate is not suitable for the solar thermal option.

Pollution Control Options

FGD

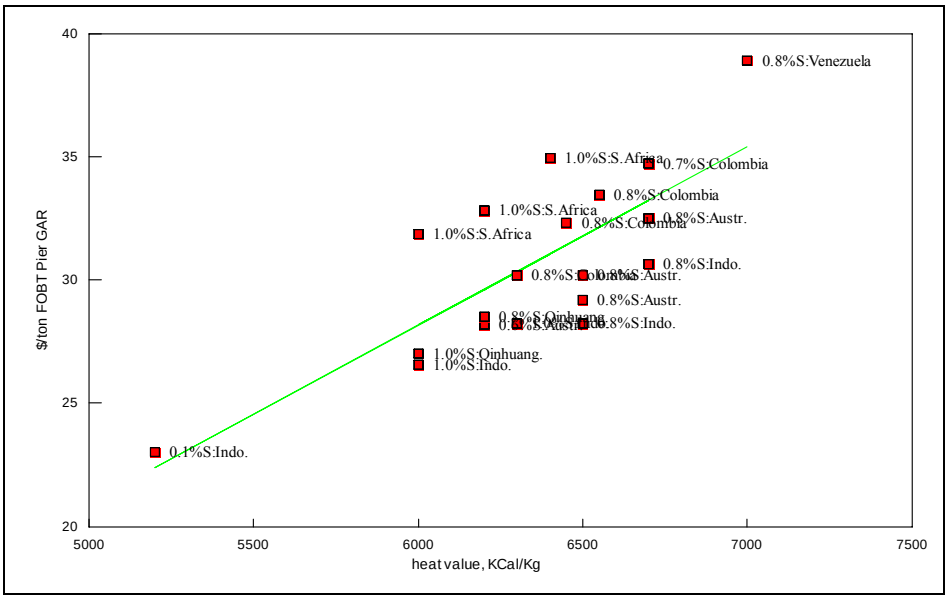
5.47 Flue gas desulfurization is not a statutory requirement in India at coal-fired plants (only one plant, near Bombay, uses the seawater absorption process). FGD was proposed for the Cogentrix project in Mangalore, but this was at the choice of the IPP and was not a condition of the environmental clearance. Given the potential concerns about the emission of acid rain precursors at coastal coal plants, we examine here the impact of an FGD requirement.

5.48 We make the following assumptions:

- The seawater absorption process is used, on the assumption that it would be applied to coastal coal-based plants only.
- Incremental capital costs are US$60/kW (Rs 2.9 million/MW).
- Degradation of heat rate is 5 percent.
- Removal of SO_2 is 80 percent.

5.49 A critical assumption is the extent of a sulfur price premium on internationally traded export coals. In North America and Europe, coal prices are significantly affected by the sulfur content of the coal (although it should be noted that the range of sulfur content, at 0.5 percent to more than 3 percent, is much greater than that of the coal traded in the Asia Pacific region, which is all less than 1 percent). As indicated in Figure 5.16, there is little evidence of a sulfur premium in these coals; the very-low-sulfur Indonesian coal, for example, which is widely used for blending, is priced almost entirely on the basis of its Btu content. Consequently we assume that there is no price benefit to be gained by using 1 percent sulfur coal with FGD rather than 0.6 percent sulfur coal without FGD (as is assumed for the reference case).

Figure 5.16: Sulfur Premium in Asia-Pacific Coal Export Markets



Efficiency Improvement Options

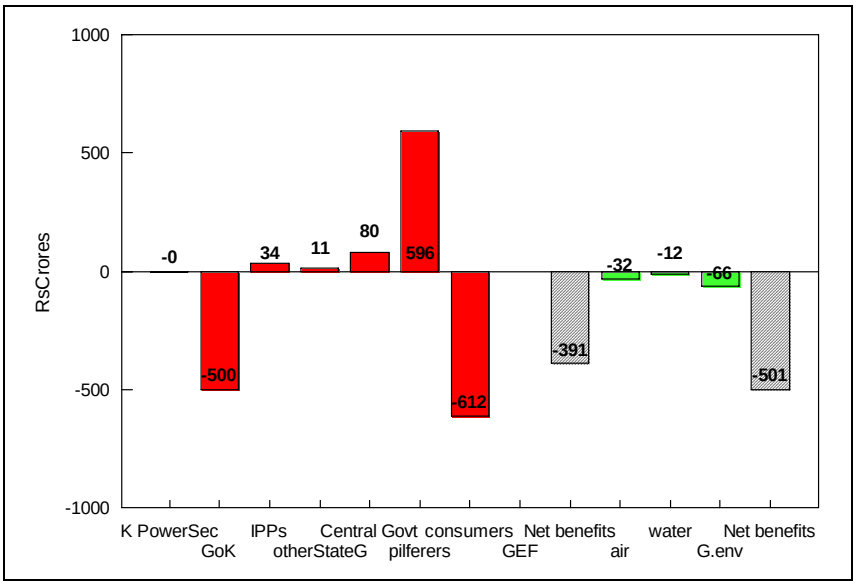
5.50 Efficiency improvement is the most obvious way to reduce the environmental burden of power generation, and is at the heart of power sector reform in India. The thermal assets of some states were at the start of the reform process in dire need of rehabilitation (as was the case at the Panipat complex in Haryana and at most older plants in UP and Bihar), but in Karnataka Raichur is relatively new and well-run, with the result that there is little scope for efficiency improvement. The reduction of technical T&D losses and nontechnical losses are, however, key elements of the Karnataka reform process.

Non-Technical Loss Reduction

5.51 The reform baseline assumes that nontechnical (NT) losses reduce to 2 percent by 2010 and to 1 percent by 2015. To examine the consequences of delays in this NT loss reduction, we posit an NT loss rate of 6 percent by 2010 and 3 percent by 2015.

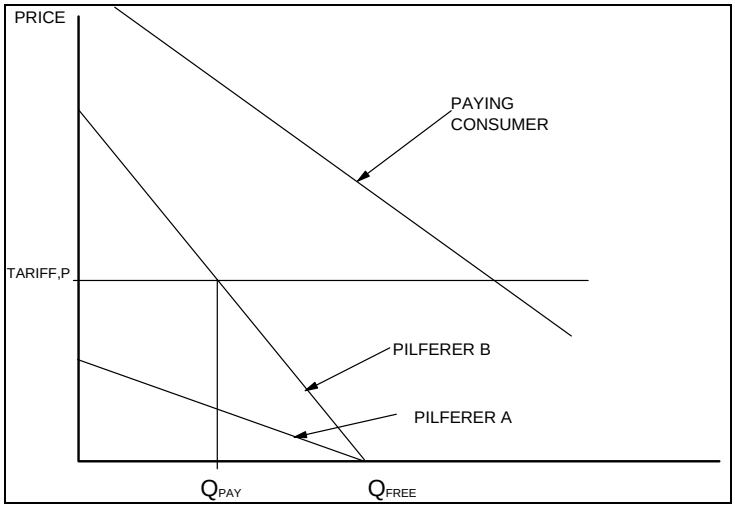
5.52 As one might expect, failure to reduce NT losses mainly benefits pilferers (Figure 5.17). There are also environmental costs, however, that arise because generation is greater than it would be should pilferage be reduced. This may seem to be a surprising result, but in fact it follows from elementary principles.

Figure 5.17: Distributional Impact of Delays in Reducing NT Loss Reduction



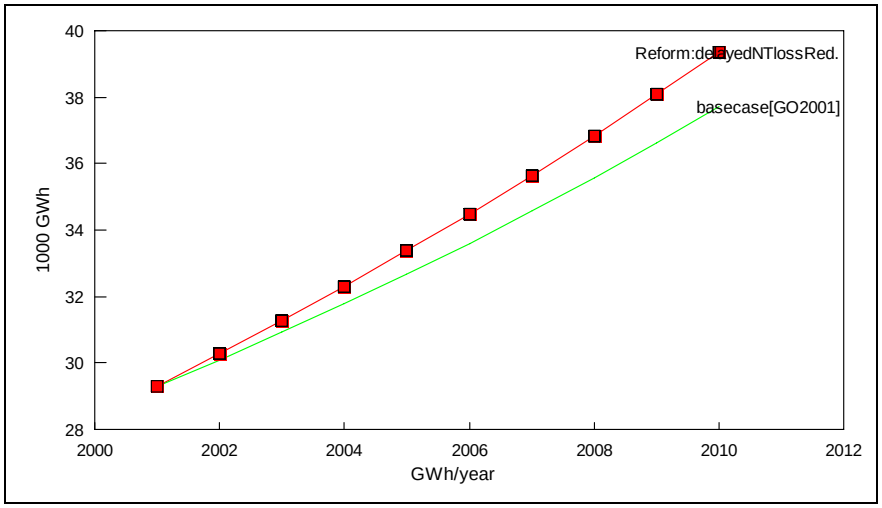
5.53 Pilferers have a demand curve very different to that of paying consumers (see Figure 5.18). By definition, the willingness to pay (WTP) of pilferers is less than the tariff, whereas for paying consumers the average WTP is greater than the tariff. Consequently, when pilferers are faced with having to pay, some will choose not to connect (see pilferer A in Figure 5.18, whose maximum WTP lies below the tariff P), and some will choose to connect, but their consumption will be significantly lower than when electricity was free (as for pilferer B, who at the tariff P will reduce his consumption from Q_{FREE} to Q_{PAY}).

Figure 5.18: Demand Curve for Pilferers



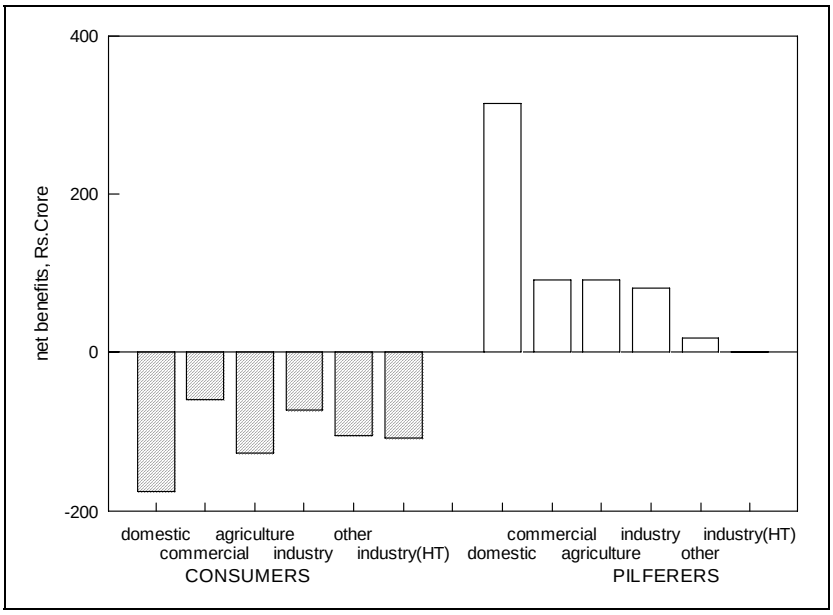
5.54 In a situation in which reform has eliminated supply constraints and those customers with a high WTP already purchase all the electricity they desire, a further reduction in NT losses would tend to reduce total consumption. This effect is accounted for in the Enviroplan demand model (Figure 5.19).

Figure 5.19: Busbar Generation Requirements



5.55 Since the cost of supplying pilferers exceeds the benefits (see Box 3), the overall result of reducing pilferage is a net economic benefit, and hence the result of Figure 5.17. It therefore follows that reducing NT losses is also beneficial to the environment. In such a situation pilferers in all categories benefit, and paying consumers in all categories lose (see Figure 5.20).

Figure 5.20: Distribution of Costs and Benefits (Delay in Meeting Non-Technical Loss Targets)



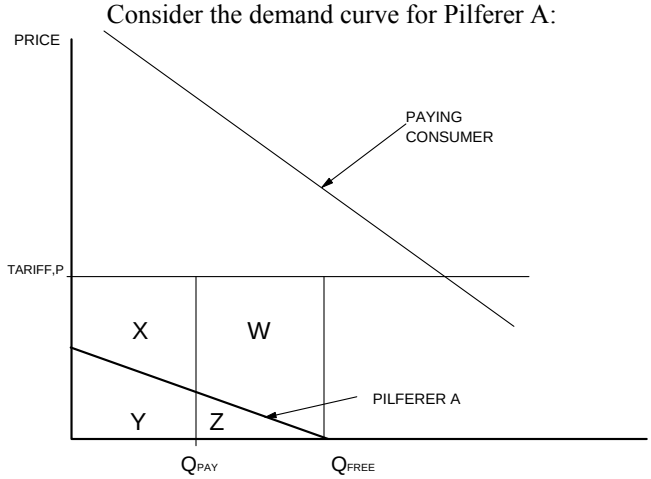
Technical Loss Reduction

5.56 The economic and environmental benefits of technical loss reduction are more obvious, since the reduction of technical losses represents always a pure gain to efficiency. However, the question remains: To what level should technical losses be reduced? What should be an appropriate target, and what are the benefits of attaining this target sooner rather than later? The maximum environmental benefit logically should be obtained when losses are as close to zero as possible, but there is an intrinsic optimum of technical T&D losses, typically in the range of 8–12 percent, that is the observed rate of T&D losses in countries with efficient power sectors.

5.57 To determine the optimal rate of T&D loss in Karnataka requires detailed engineering economic and load flow studies that lie beyond the scope of this report. To illustrate the environmental consequences of delays in reaching the reform targets, we posit a scenario in which technical losses fall only to 20 percent by 2010, rather than to 14 percent as assumed in the baseline, and to only 15 percent by 2015, rather than to 12 percent.

Box 3: Economic Costs and Benefits of Pilferage

Consider the demand curve for Pilferer A:



The costs of supplying the pilferer's consumption (assuming that the tariff reflects economic costs) is $P \times Q_{FREE}$, which is equal to the area $X + Y + W + Z$. The benefit to the pilferer is the area under his demand curve; that is, $Y + Z$. The net economic cost to society of supplying the pilferer therefore is $X + W$.

Since the maximum WTP of pilferer A is less than the tariff, if faced with metering this pilferer would choose not to connect. He therefore would experience a loss of benefits in the amount $Y + Z$. Society would avoid the economic cost of supplying him with free power, however, as defined by the area $X + Y + W + Z$. The net economic benefit is the difference between the two; that is, $X + W$.

	With pilferage	After metering	Net Impact
Pilferer benefits	*Y+Z*	*0*	*-Y-Z*
Power company's cost of supply	*-X-Y-W-Z*	*0*	*X+Y+W+Z*
Net benefit	*-Y-W*	*0*	*X+W*

5.58 The main effect of delays in meeting technical T&D loss reduction targets is an increase in the busbar generation requirement (Figure 5.21), but without a concomitant increase in economic benefits. The result is the predictable loss to most stakeholders shown in Figure 5.22.

Figure 5.21: Impact of Technical Loss Reduction on Busbar Generation Requirement

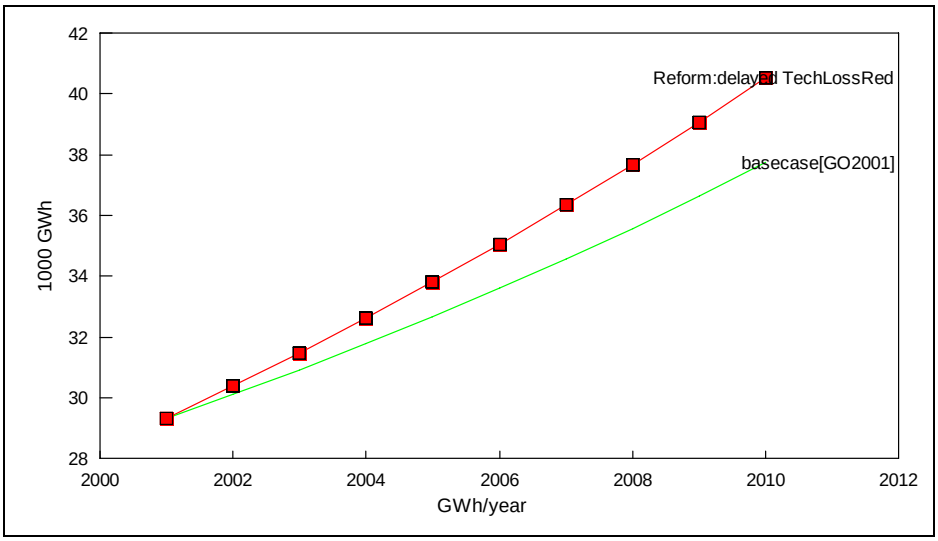
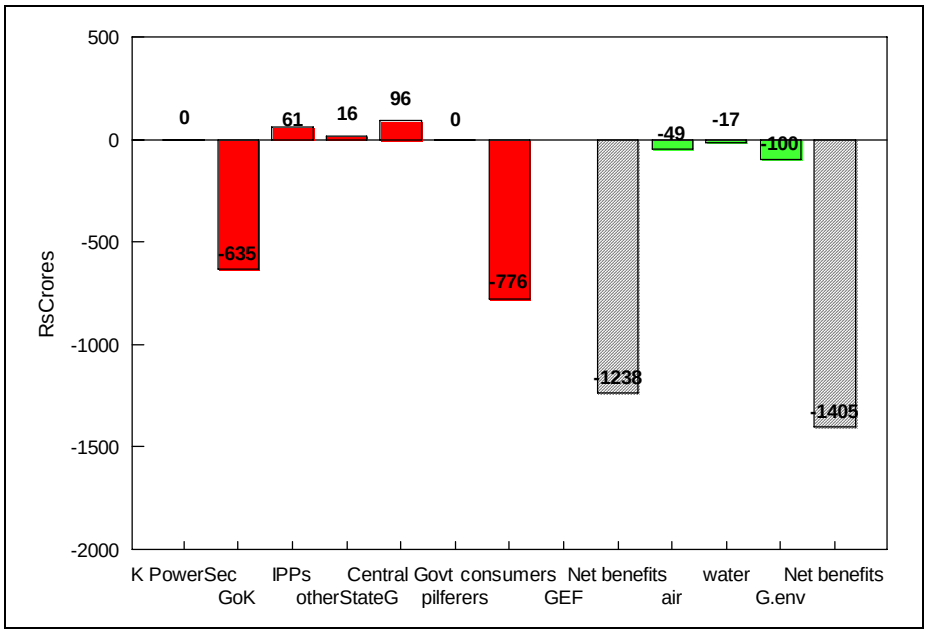


Figure 5.22: Distribution of Costs and Benefits of Delays in Achieving Technical Loss Reduction Targets



5.59 Thus everyone in Karnataka would lose from a delay in the achievement in the technical loss reduction targets. Since the higher generation is met from out-of-state sources, the center's returns and out-of-state coal royalty revenues would increase, and these are the only (apparent) winners. The additional generation requirement would impose additional environmental burdens.

6

Results

Multi-Attribute Analysis

6.1 A multi-attribute analysis of the alternative scenarios was carried out by comparing the corresponding results. The results and underlying assumptions are summarized in Table 6.1. SO_2 and total suspended particulate (TSP) emissions are given in present value terms, discounted at the rate of 12 percent as they are local pollutants. For GHGs, both discounted and undiscounted values are shown.

Table 6.1: Matrix of Attributes

	economic	environment						financial		
	benefits	undisc. GHG	discounted GHG	water use	NOx	SOx	PM-10	GoK	consumers	pilferers
	[RsCr]	[mt]	[mt]	[billGal]	[1000t]	[1000t]	[1000t]	[RsCr]	[RsCr]	[RsCr]
ReformBaseline(	32301	159	46	159	422	516	110	-3979	30214	1697
stalledReform	23377	142	44	164	434	518	115	-9774	26434	3097
EAct	32945	164	47	164	433	530	113	-3616	30462	1697
maxHy	32726	151	44	161	401	505	108	-3801	30584	1697
nuclear	31990	153	45	164	413	506	108	-3966	30461	1697
domGas: WOP=	31378	140	43	165	408	469	100	-5216	30819	1697
domGas, WOP=	32293	140	43	165	408	469	100	-3616	30161	1697
imported Coal	33510	147	44	159	418	481	109	-3979	26785	1697
imp.coal+FGD	33104	149	44	159	418	443	109	-3808	25858	1697
TalcherHVDC	33973	142	43	159	418	520	109	-4417	32418	1697
allDSM	32819	159	45	159	417	516	110	-3824	30685	1690
Reform:delayedI	31910	163	47	162	433	523	112	-4479	29602	2293
Reform:delayed	31063	165	47	163	440	526	112	-4614	29438	1697
bagasse	32958	152	44	162	403	491	105	-3873	31062	1697
smallHydro	32285	154	44	160	403	501	107	-3957	30163	1697
wind[newTariff]	31662	155	45	157	414	509	109	-4324	29909	1697

Table 6.2: Differential Impacts: Changes Against the GO 2001 Base Case

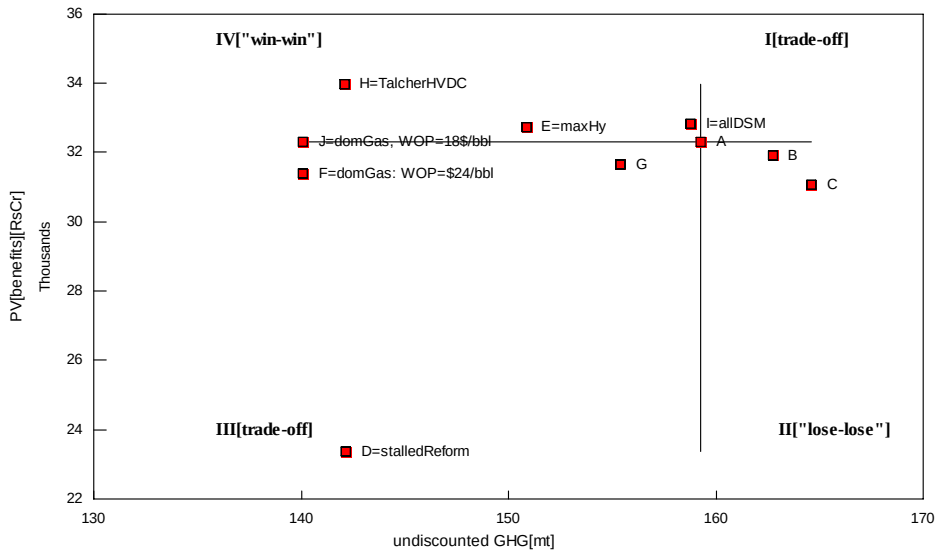
	economic	environment						financial		
	benefits	undisc. GHG	discount. GHG	water use	NOx	SOx	PM-10	GoK	consumers	pilferers
	[RsCr]	[mt]	[mt]	[billGal]	[1000t]	[1000t]	[1000t]	[RsCr]	[RsCr]	[RsCr]
stalledReform	-8924	-17	-2	5	12	2	5	-5795	-3780	1400
EAct	644	5	1	5	11	14	3	363	248	-0
maxHy	425	-8	-2	2	-21	-11	-3	178	370	0
nuclear	-311	-7	-1	5	-8	-10	-2	13	247	0
domGas: WOP=$24/bbl	-923	-19	-3	5	-14	-46	-10	-1237	605	0
domGas, WOP=18$/bbl	-8	-19	-3	5	-14	-46	-10	363	-53	0
imported Coal	1209	-13	-2	0	-3	-35	-1	-0	-3429	0
imp.coal+FGD	803	-11	-2	0	-3	-73	-1	170	-4356	0
TalcherHVDC	1672	-17	-3	0	-3	4	-1	-439	2204	0
allDSM	518	-1	-0	0	-5	1	0	155	471	-7
delayed NT loss Red.	-391	3	1	2	11	7	2	-500	-612	596
delayed Tech loss Red.	-1238	5	1	3	18	10	2	-635	-776	0
bagasse	657	-7	-2	3	-19	-25	-5	106	848	0
smallHydro	-16	-5	-1	0	-19	-15	-3	22	-51	0
wind[newTariff]	-639	-4	-1	-2	-8	-7	-1	-346	-305	-0

Negative=decrease, positive=increase in the attribute value

Greenhouse Gas Emissions

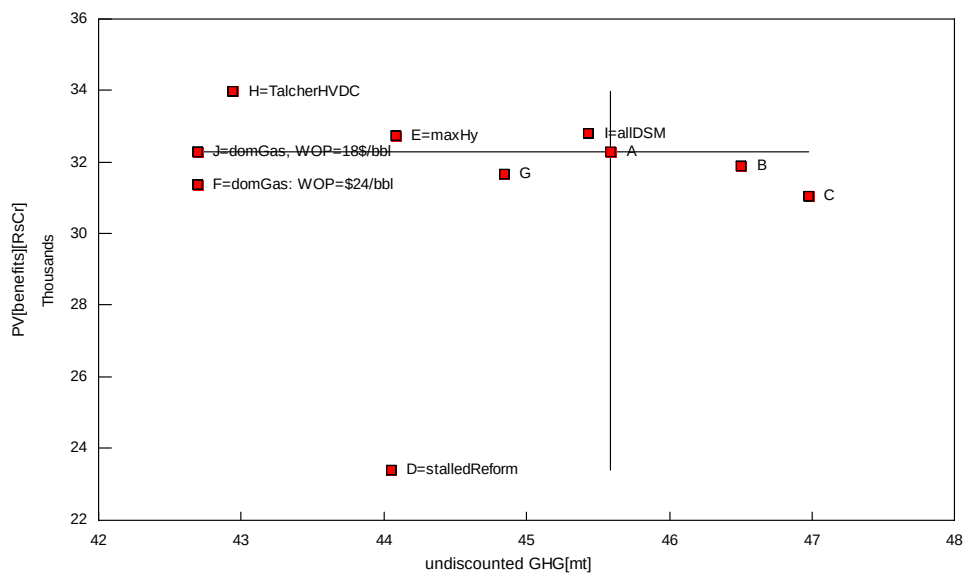
6.2 Figure 6.1 shows the trade-offs between undiscounted GHG emissions and economic benefits. The quadrants are defined by the reference reform case that currently is under implementation in Karnataka. Options in Quadrant II are “lose-lose” with respect to the base case (such as delays in T&D loss reduction); options in Quadrant IV are “win-win” (such as bagasse and imported coal). Options in Quadrants I and III require trade-offs: for example wind and nuclear in Quadrant IV have lower GHG emissions but higher costs, while the options in Quadrant II have higher GHG emissions but lower costs.

Figure 6.1: GHG Emissions (Undiscounted) versus Economic Benefit



A	**=ReformBaselineGO2001**
B	=Reform:delayedNTlossRed.
C	=Reform:delayed TechLossRed
D	=Stalled reform
E	=MaxHy
F	=Domestic Gas: WOP=$24/bbl
G	=Wind[newTariff]
H	=TalcherHVDC
I	=All DSM
J	=Domestic Gas, WOP=18$/bbl

Figure 6.2: Economic Benefit versus Discounted GHG Emissions



6.3 The corresponding costs of discounted avoided carbon are shown in Table 6.3. Only those in Quadrant III[62] —that is, those that have higher costs than the base case scenario, such as wind and small hydro, but that have lower GHG emissions—theoretically are eligible for Global Environment Fund (GEF) funding.

Table 6.3: Cost of Avoided Carbon

	d(cost) [$m]	undiscounted d(carbon) [mt]	avoided cost $/ton [$/ton]	
stalledReform	-1859	-17.1	108.6	trade-off
EAct	134	4.9	27.6	trade-off
maxHy	89	-8.4	-10.5	win-win
nuclear	-65	-6.6	9.8	trade-off
domGas: WOP=$24/bbl	-192	-19.2	10.0	trade-off
domGas, WOP=18$/bbl	-2	-19.2	0.1	trade-off
imported Coal	252	-12.8	-19.8	win-win
imp.coal+FGD	167	-10.7	-15.7	win-win
TalcherHVDC	348	-17.2	-20.2	win-win
allDSM	108	-0.5	-209.6	win-win
delayed NT loss Red.	-81	3.4	-23.7	lose-lose
delayed Tech loss Red.	-258	5.3	-48.5	lose-lose
bagasse	137	-7.1	-19.2	win-win
smallHydro	-3	-5.4	0.6	trade-off
wind[newTariff]	-133	-3.9	34.2	trade-off

6.4 These costs of avoided carbon use the GEF methodology in which the carbon savings over the project lifetime are added (that is, without discounting). This gives the appearance of a lower cost of avoided carbon than is actually the case. When emissions are discounted, as they need to be for any calculation of carbon revenue streams from, say, the sale of carbon credits in a global carbon credit market, the costs of avoided carbon are roughly four to five times greater. For example, for wind power the discounted avoided cost of carbon is US$140/ton, compared to US$34/ton in the undiscounted case.

6.5 The Karnataka results may be compared to the other case study states.[63] Table 6.4 shows this comparison in terms of U.S. dollars per ton of avoided carbon emissions. In all states, DSM and biomass utilization are win-win. Likewise in all states, gas utilization requires a trade-off. In Uttar Pradesh, the cost of avoided carbon associated with LNG is high, at US$20/ton carbon, because of the long transportation

[62] Large hydro ("MaxHy") also lies in this quardrant, but does not qualify for GEF subsidies.

[63] Administrative Staff College of India (1999) and SCADA (1999).

distance; in Bihar it is high (US$24.1/ton carbon) because it must compete with low-cost mine-mouth coal. In all states except Bihar the large hydro option is win-win.[64]

Table 6.4: Comparison with Other States: Cost of Avoided Carbon in US$/Ton Carbon (Measured Against Reform Scenario) *(win-win in bold italics)*

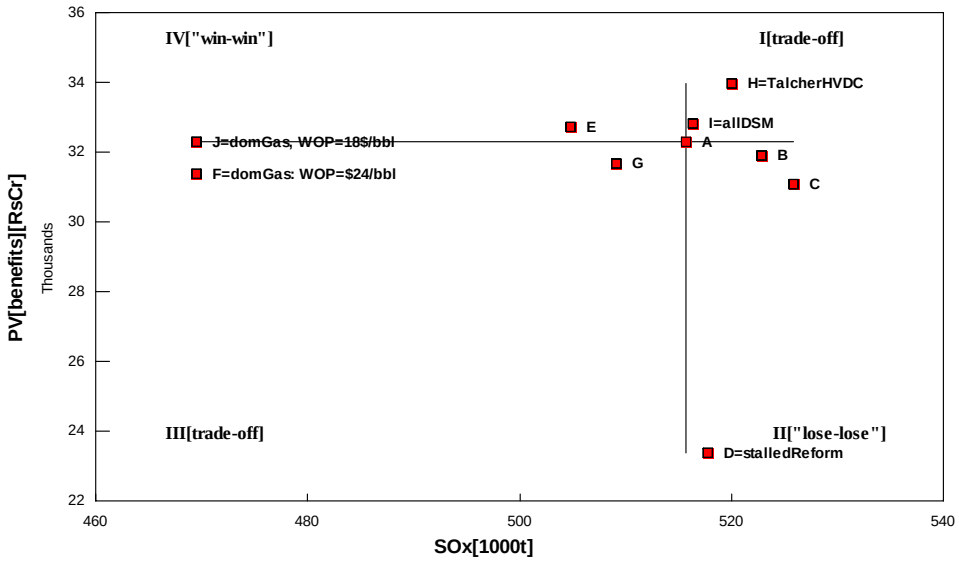
	Karnataka	Rajasthan	Uttar Pradesh	Andhra Pradesh	Bihar
DSM				-28.9 (lighting)	-18
DSM-agriculture	-209	-124	-37	-14.3	
Biomass	Bagasse -19		biomass combustion -45	bagasse -18	bagasse -44
Refinery residue				3.3	
Further T&D rehab				-19.4	-36
LNG/gas	10	9.2	20 (HBJ pipeline)	0.7	24.1
Thermal plant rehabilitation			-53 (lose-lose)	-71.5	win-win (part of reform scenario)
Mini hydel	0.6		-17	4	-21.1
Large hydro	-10.5	-7.7	-22 (Nepal Exports)	-8.4	34
Nuclear	10	8	27	9.5	2.5
Wind	34	26		22	
Solar		314 (Mathania)		100 (PV)	108 (PV)
Coal washing			114	167	

[64] In Bihar, this is attributable to the high costs associated with the Koel-Karo project that was used as the hydro candidate project.

SO_2 Emissions

6.6 Figure 6.3 displays the trade-offs between system cost and SO_2 emissions. As should be expected, the gas and imported coal+FGD scenarios, with their specific emphasis on SO_2 emission reductions, perform the best in reducing SO_2 emissions.

Figure 6.3: System Cost versus SO_2 Emissions (Discounted)

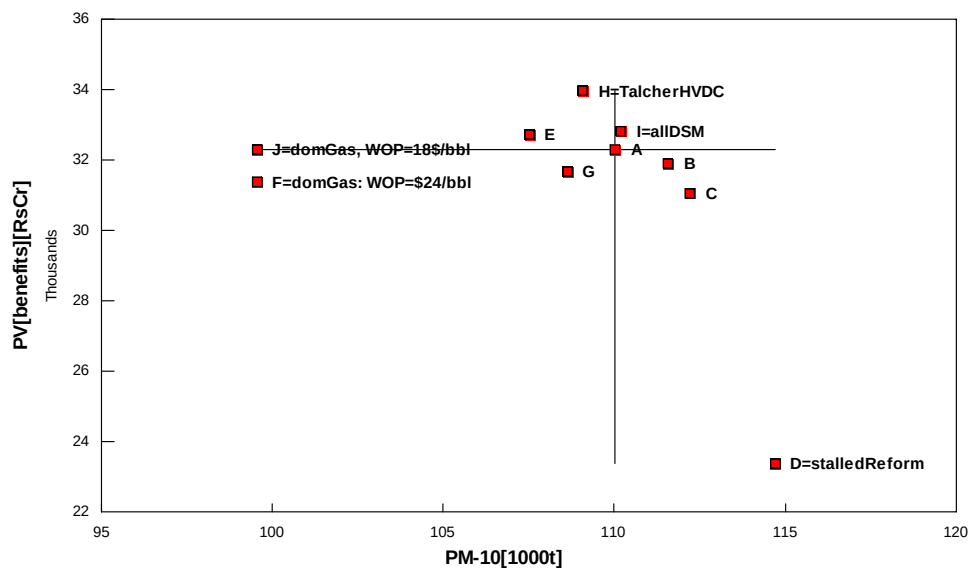


A	**=ReformBaselineGO2001**
B	=Reform:delayedNTlossRed.
C	=Reform:delayed TechLossRed
D	=Stalled reform
E	=MaxHy
F	=Domestic Gas: WOP=$24/bbl
G	=Wind[newTariff]
H	=TalcherHVDC
I	=All DSM
J	=Domestic Gas, WOP=18$/bbl

Particulate Emissions

6.7 The trade-offs between system cost and particulate emissions are shown in Figure 6.4. As washed coal increasingly is used at Raichur, particulate emissions may be expected to fall further—although the modeling does not take into account the higher reliability of electrostatic precipitators (ESPs) when using washed coal. As demonstrated at the Satpura field trials, washed coal results in a significantly smaller number of ESP failures, and this can have a disproportionate effect on annual emissions.[65]

Figure 6.4: System Cost versus Particulate Emissions (Discounted)



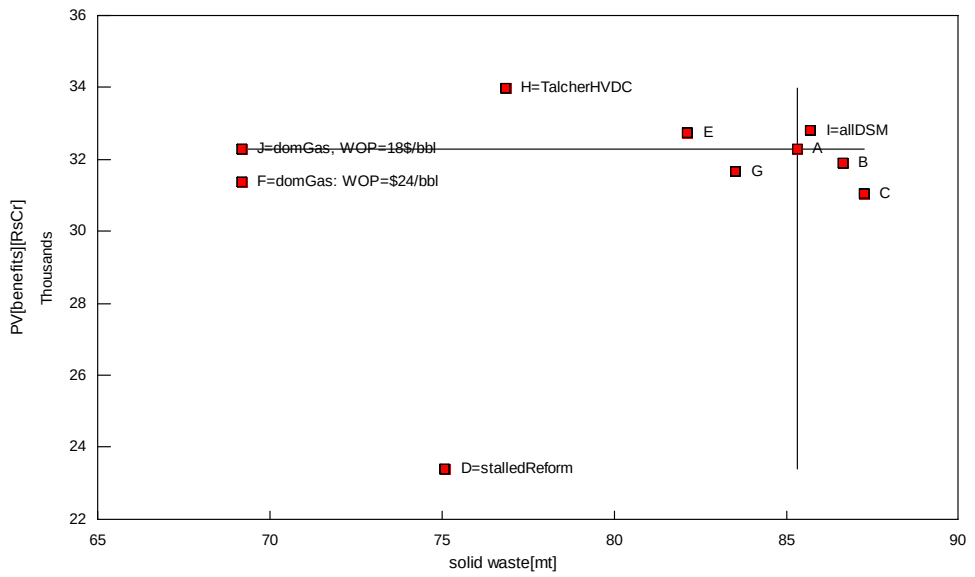
A	**=ReformBaselineGO2001**
B	=Reform:delayedNTlossRed.
C	=Reform:delayed TechLossRed
D	=Stalled reform
E	=MaxHy
F	=Domestic Gas: WOP=$24/bbl
G	=Wind[newTariff]
H	=TalcherHVDC
I	=All DSM
J	=Domestic Gas, WOP=18$/bbl

[65] A field failure, unless accompanied by immediate shut down, can result in emission performance going from the normal 99.7 percent to 80 percent—a 666-fold increase in emissions. It follows that one 12-hour period of improper performance can result in the emission of the same amount of particulates as an entire year of normal operation at 99.7 percent.

Solid Waste Disposal

6.8 Figure 6.5 shows the trade-offs between system cost and solid waste (mainly ash) generation. The FGD scenario assumes use of the seawater absorption process, as was planned for the Cogentrix plant, on coastal plants only. These do not generate scrubber sludge as would be the case were FGD applied at inland locations.

Figure 6.5: System Cost versus Waste Disposal Quantities (Undiscounted)



A	**=ReformBaselineGO2001**
B	=Reform:delayedNTlossRed.
C	=Reform:delayed TechLossRed
D	=Stalled reform
E	=MaxHy
F	=Domestic Gas: WOP=$24/bbl
G	=Wind[newTariff]
H	=TalcherHVDC
I	=All DSM
J	=Domestic Gas, WOP=18$/bbl

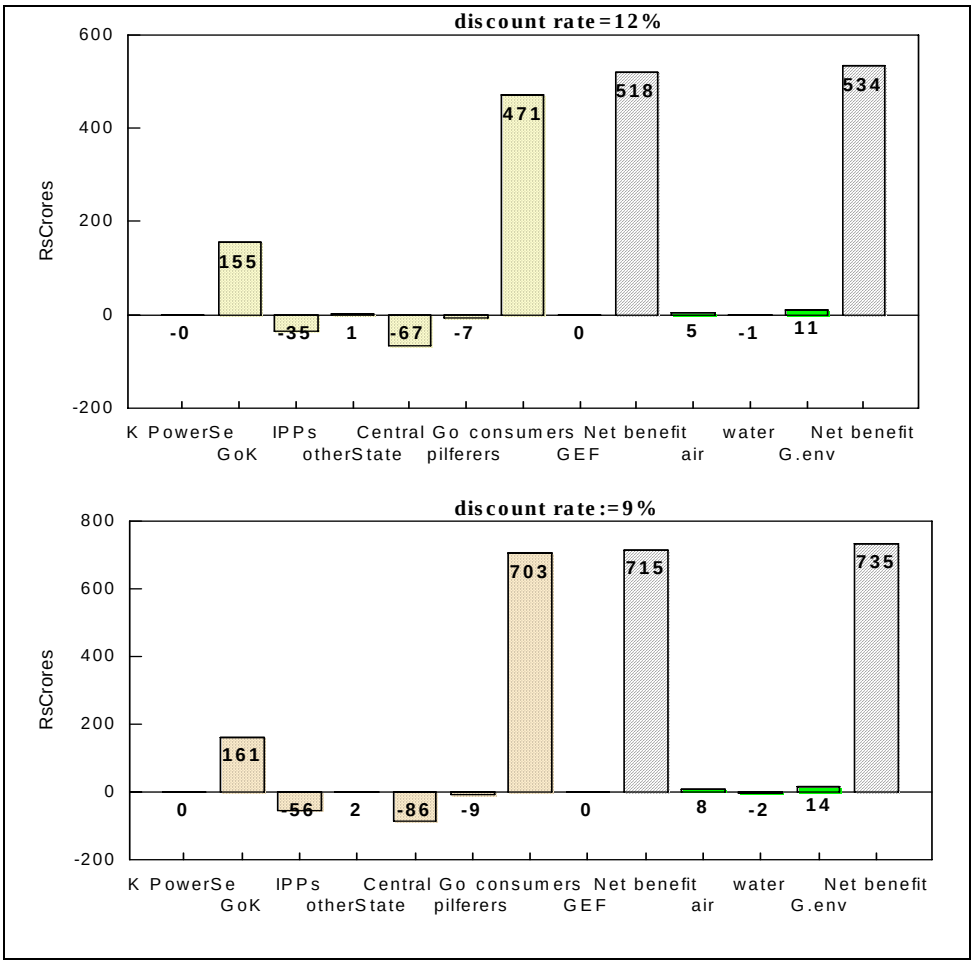
7

Sensitivity Analysis

Discount Rate

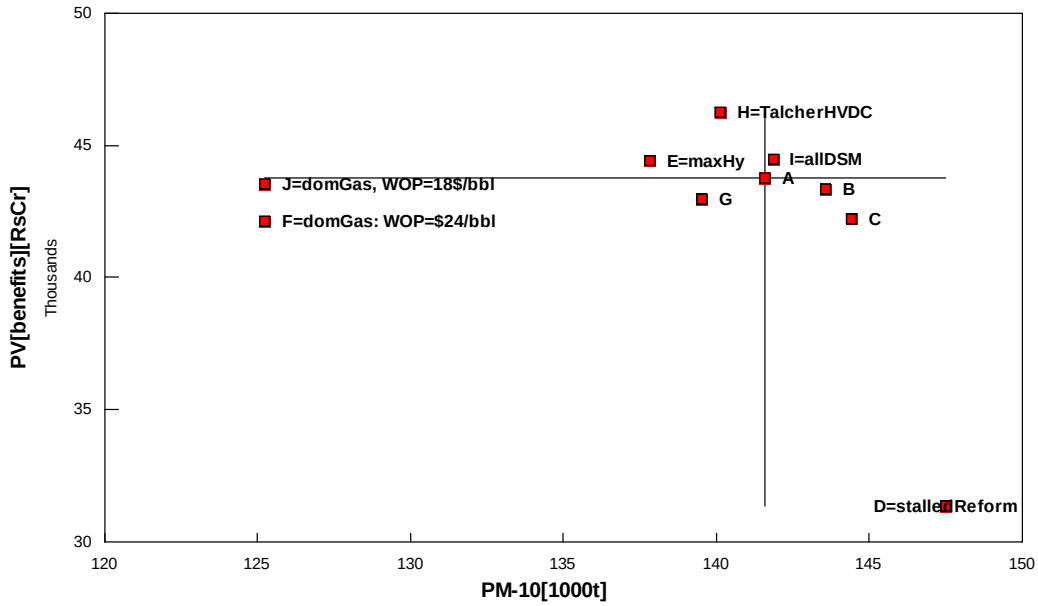
7.1 The results are robust with regard to the discount rate. A rate of 12 percent is used in this report, but as demonstrated in Figure 7.1, lowering the rate to 9 percent produces completely analogous results, with the difference that, as one would expect, the magnitude of the NPVs is greater. Further lowering of the discount rate shows similar results.

Figure 7.1: Impact of Discount Rate on DSM (as NPV)



7.2 Figure 7.2 shows, for selected options, the trade-off between particulate emissions and the PV of benefits at 9 percent (compare with Figure 6.4, which uses a 12 percent discount rate). Although the relative positions of individual options shift slightly, the essential conclusions remain: stalled reform and delays in achieving technical and nontechnical loss reduction targets are strongly lose-lose.

Figure 7.2: Trade-Offs: System Cost versus Particulate Emissions at 9 Percent Discount Rate



A	**=ReformBaselineGO2001**
B	=Reform:delayedNTlossRed.
C	=Reform:delayed TechLossRed
D	=Stalled reform
E	=MaxHy
F	=Domestic Gas: WOP=$24/bbl
G	=Wind[newTariff]
H	=TalcherHVDC
I	=All DSM
J	=Domestic Gas, WOP=18$/bbl

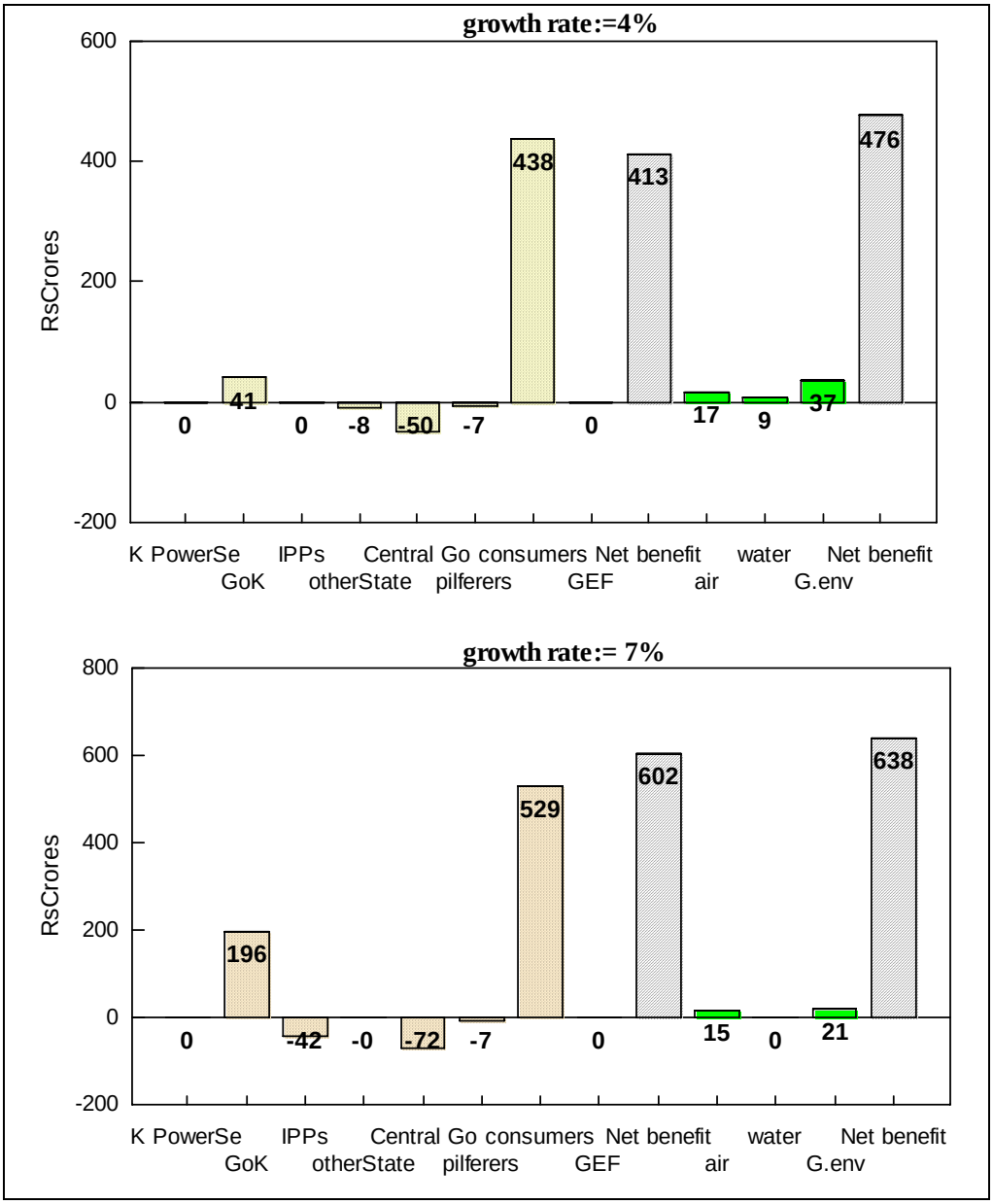
Demand Growth

7.3 The sensitivity of the main conclusions shows similar robustness to the second major assumption regarding long-term demand growth. In the reform base case, the aggregate consumption demand growth rate over the 20-year time horizon is 5.5 percent. While one would not expect the conclusions for supply-side options to be sensitive to the underlying demand growth rate—for example, wind power will be more expensive and will reduce emissions, no matter what the demand growth rate—one might suppose that the conclusions regarding stalled reform and DSM are sensitive to the demand growth assumption.[66]

[66] This issue was raised by government officials at the Bangalore Seminar in July 2003.

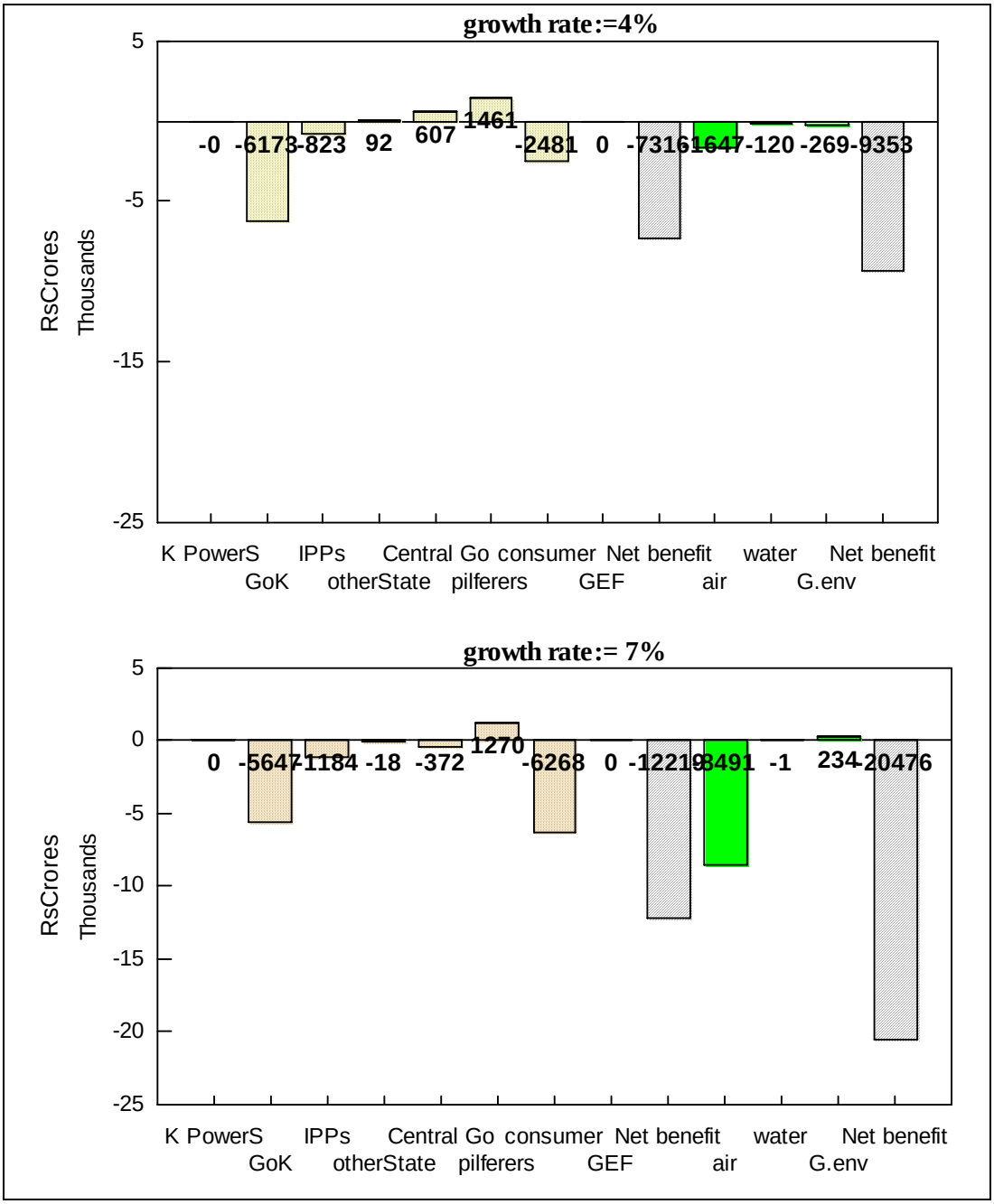
7.4 Figure 7.3 shows that the impact of DSM at 4 percent and 7 percent growth rates (Rs 4.16 billion and Rs 6.38 billion, respectively) brackets its impact at 5.5 percent growth rate (Rs 5.18 billion) (see Figure 7.1, 12% discount rate case).

Figure 7.3: Impact of DSM at 4 Percent and 7 Percent Aggregate Demand Growth Rates



7.5 The results for stalled reform are analogous: again, the net economic benefits at 4 percent and 7 percent demand growth (Rs 93.58 billion and Rs 204.76 billion, respectively) bracket the base case result of Rs 128.74 billion (see Figure 7.4).

Figure 7.4: Impact of Stalled Reform at 4 and 7 Percent Demand Growth



Carbon Damage Costs

7.6 This study uses a value for carbon (US$15/ton) that is based on the PCF expectations of the market for carbon emissions reductions. This market price does not necessarily reflect actual future damage costs: indeed, the IPCC estimates of the range of damage costs are significantly higher, reaching as much as US$150/ton carbon. While these estimates are strongly dependent upon the discount rates used—damage cost estimates in the US$50–150/ton carbon generally are based on discount rates of less than 5 percent—the question remains whether or not the use of such higher values would change any of the conclusions of the study.

7.7 A win-win option such as DSM (see Table 6.3) remains win-win whatever is the actual value of carbon damage. The cost of avoided carbon represented in Table 6.3 is equivalent to the switching value for the damage cost: thus, for example, nuclear becomes economic when the damage cost is US$9.8/ton or greater.

7.8 Table 7.1 shows the net economic benefits at US$15/ton (as used above) and at US$50/ton and US$150/ton (the upper and lower markers of the range of IPCC damage cost estimates). The highlighted cells indicate at what point those options that are uneconomic in the absence of carbon externalities (that is, that show a negative value in Column [1]), become economic. Nuclear, gas, and small hydro become economic at US$15/ton and wind at US$50/ton. Those options associated with stalled reform are not economic even at US$150/ton.

Table 7.1: Net Economic Benefits at IPCC Damage Cost Valuations

	Economic benefit, before carbon credits	Carbon benefits @US$15/ton	Net economic benefit	Carbon benefit at US$50/ton (IPCC low)	Net economic benefit	Carbon benefit at US$150/ton (IPCC high)	Net economic benefit
	[1]	[2]	[3=1+2]	[4]	[5=1+4]	[6]	[7=1+6]
Stalled reform	-1859	111	-1748	369	-1490	1107	-752
E Act	134	-99	36	-328	-194	-985	-851
Max hydro	89	108	197	361	450	1083	1172
Nuclear	-65	71	**6**	236	171	709	644
Domestic gas: WOP=US$24/bbl	-192	208	**16**	694	502	2083	1891
Domestic gas, WOP=US$18/bbl	-2	208	**207**	694	693	2083	2082
Imported coal	252	141	393	471	723	1413	1665
Imported coal + FGD	167	118	286	394	562	1183	1351
Talcher HVDC	348	191	539	635	984	1906	2254
All DSM	108	11	119	37	145	110	218
Delayed NT loss Red.	-81	-66	-148	-220	-302	-661	-743
Delayed tech loss Red.	-258	-100	-358	-333	-591	-999	-1257
Bagasse	137	121	258	404	541	1213	1350
Small hydro	-3	84	**81**	281	278	844	840
Wind [new tariff]	-133	54	-80	179	**46**	537	403

8

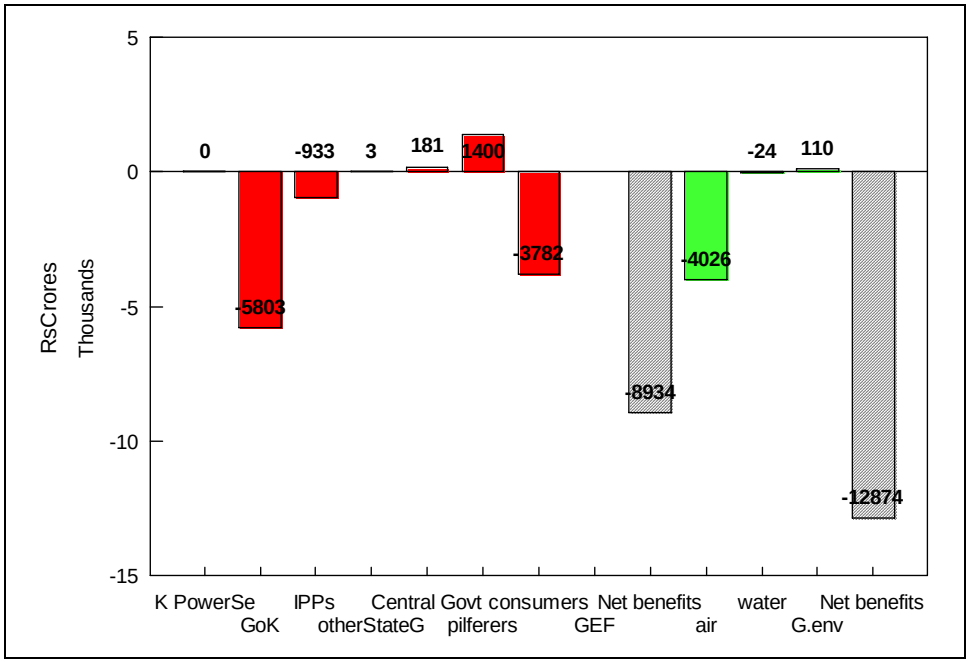
Summary and Conclusions

8.1 The main findings of the study may be summarized by reference to the various issues posed at the outset. These are framed in terms of the impacts on stakeholders.

Stalled Reform

8.2 In the stalled reform scenario, no IPPs can reach financial closure and capacity additions are limited to Karnataka's share in central sector projects. There is no further improvement in T&D losses, and no further tariff increases. This results in the impacts on stakeholders, relative to the reform baseline, demonstrated in Figure 8.1.

Figure 8.1: Impact of Stalled Reform



8.3 We make the following conclusions in the event that the reform program stalls:

- The only group that wins if reforms stall is pilferers. Although pilferers derive some economic benefit from their consumption, these benefits are smaller than the social costs of supplying them.
- All the other stakeholders lose, with the exception of the global environment, which benefits from lower generation and lower GHG emissions.
- IPPs lose because they cannot bring their projects to financial closure, and hence they lose the equity returns they otherwise would earn under the reform program
- Stalled reform represents a significant loss for the local environment because the health damages due to emissions from self-generation are significantly higher than those due to remote grid stations.
- Paying consumers lose because self-generation does not cover all power shortages (that is, there remains unmet demand) and because self-generation is more expensive in both economic and financial terms than is grid supply.

8.4 Continued progress on reform in fact brings the single most important benefit to the environment.

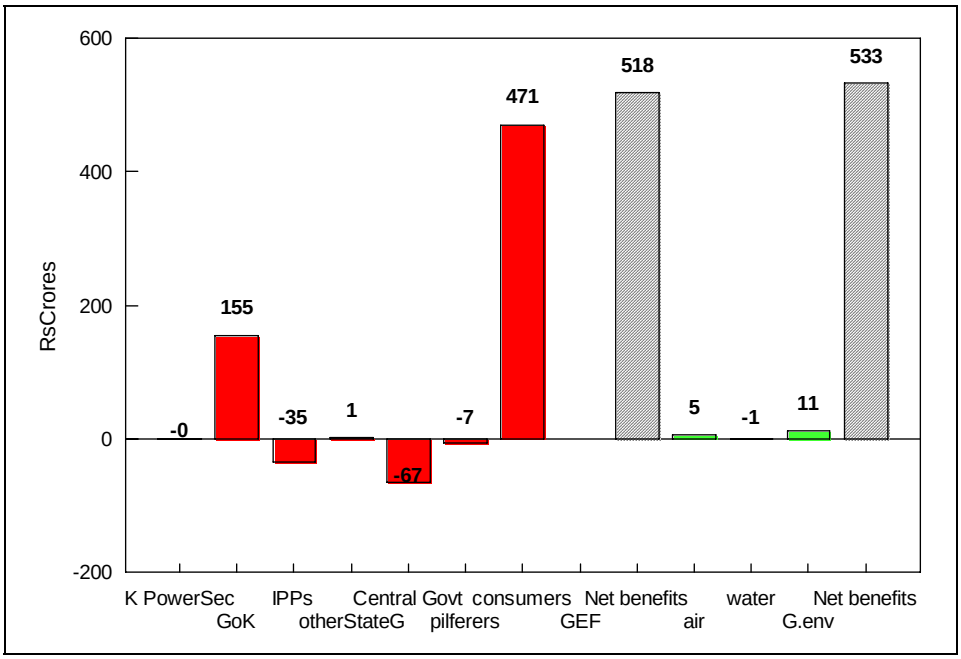
DSM

8.3 In the DSM scenario we implement a portfolio of individual DSM programs in the domestic, commercial, and agricultural sectors. This results in the impacts on stakeholders as shown in Figure 8.2.

8.4 We conclude that:

- The results conform to the classic pattern for DSM: Economic benefits to society as a whole and significant benefits to the environment and to consumers.
- The gains to consumers and the environment represent real economic gains, contributing to increased economic growth for Karnataka.

Figure 8.2: Impact of DSM

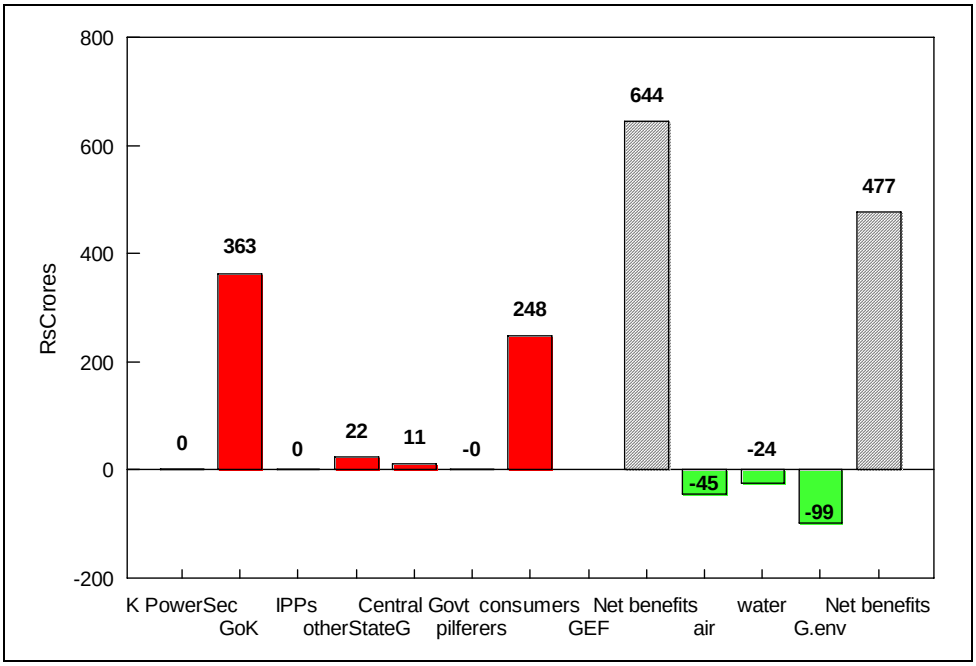


8.5 The DSM measures proposed are all in the subsidized sectors, where for the next few years every additional kWh sold implies a financial loss for the sector. Not only do those who implement DSM gain, but so too do those who do not implement DSM, because, all else being equal, lower financial losses means lower tariffs and/or lower revenue subsidies from the GoK.

Impact of the 2003 Electricity Act

8.6 Under the 2003 Electricity Act, generating companies are free to sell to any licensees. They may be expected to do this when they would otherwise need to back down, or if more prompt payment may be secured by selling a generating plant's output to an out-of-state buyer. This may be expected to improve the plant load factors of the nation's best operating thermal projects (see Figure 8.3).

Figure 8.3: Impact of the 2003 Electricity Act



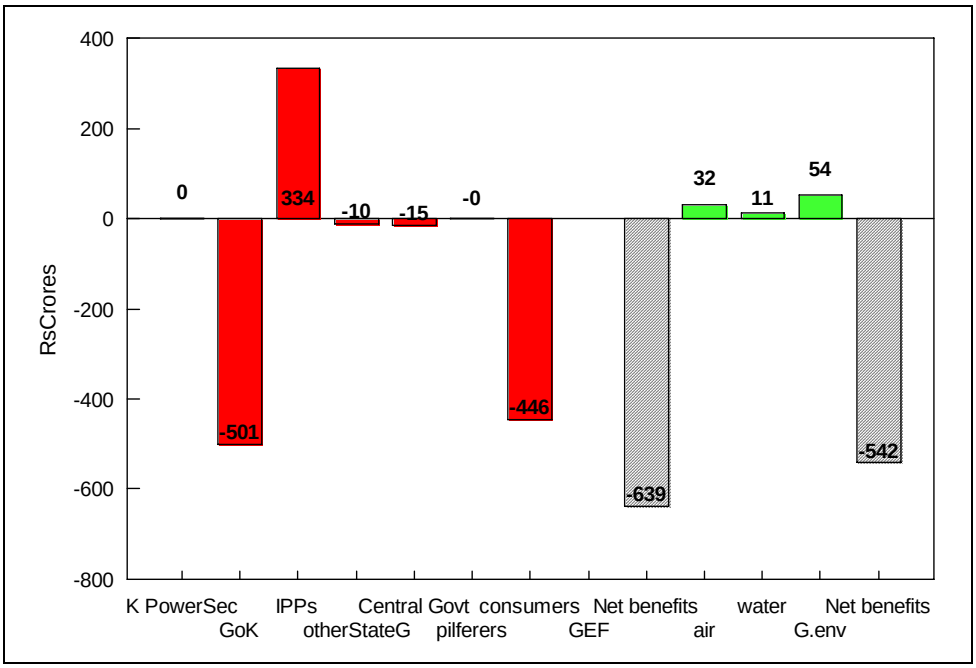
8.5 We note that:

- The economic benefits from better utilization of thermal plants are substantial, amounting to Rs 6.44 billion.
- These economic benefits derive from increased sales to other states (and to PTC) of Rs 10.18 billion. These sales are offset by higher generating costs, of Rs 3.73 billion.
- If the GoI maintains its policy of not subsidizing HSD, and if the Karnataka regulator maintains the trend of decreasing the HT industrial tariff (in real terms), the provision of the Electricity Act that mandates open transmission access is unlikely to lead to a significant increase in captive generation, because the variable costs of diesel operation (at around Rs 5.5/kWh) are significantly greater than the present HT tariff.
- Although the environmental burdens increase in Karnataka, these are offset by a corresponding decrease in the importing state. Since importing states tend to be those with less efficient thermal plants, there may be a greater offsetting environmental benefit in the importing state (and thus there is an environmental gain to India as a whole)

Impact of Renewable Energy: Wind Power

8.6 The study has examined the impacts of a maximum wind power development scenario under which some 600MW of wind power would be built over a 10-year period (representing 50 percent of projects presently allotted by GoK). Even with the expected decline in capital costs wind power is not economic, with a negative benefit of Rs 6.39 billion. Even when the positive environmental benefits are added, the loss is still Rs 5.42 billion (see Figure 8.4).

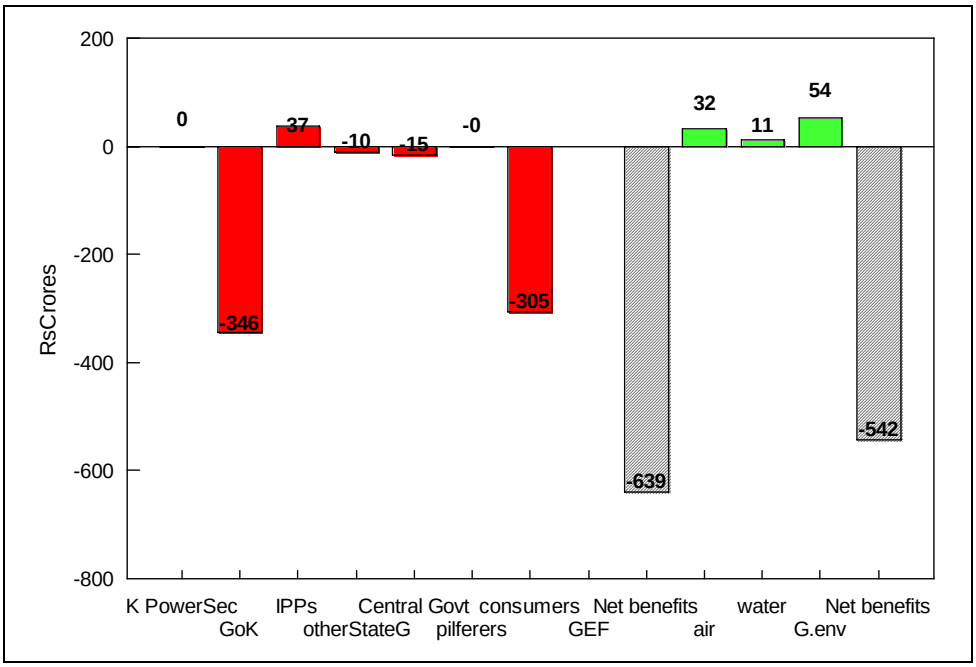
Figure 8.4: Impact of Wind Power Under the Old Tariff (Relative to Reform Baseline)



8.7 IPP developers capture a significant financial surplus, which means that the economic loss plus the IPP surplus results in heavily unfavorable impacts both on consumers and on the GoK. The scenario is therefore unsustainable despite the environmental benefits.

8.8 Under the new tariff negotiated between KPTCL and the developers, the IPP surplus (that is, the returns in excess of the opportunity cost of capital) is substantially reduced (see Figure 8.5).

Figure 8.5: Impact of Wind Power Under the New Tariff

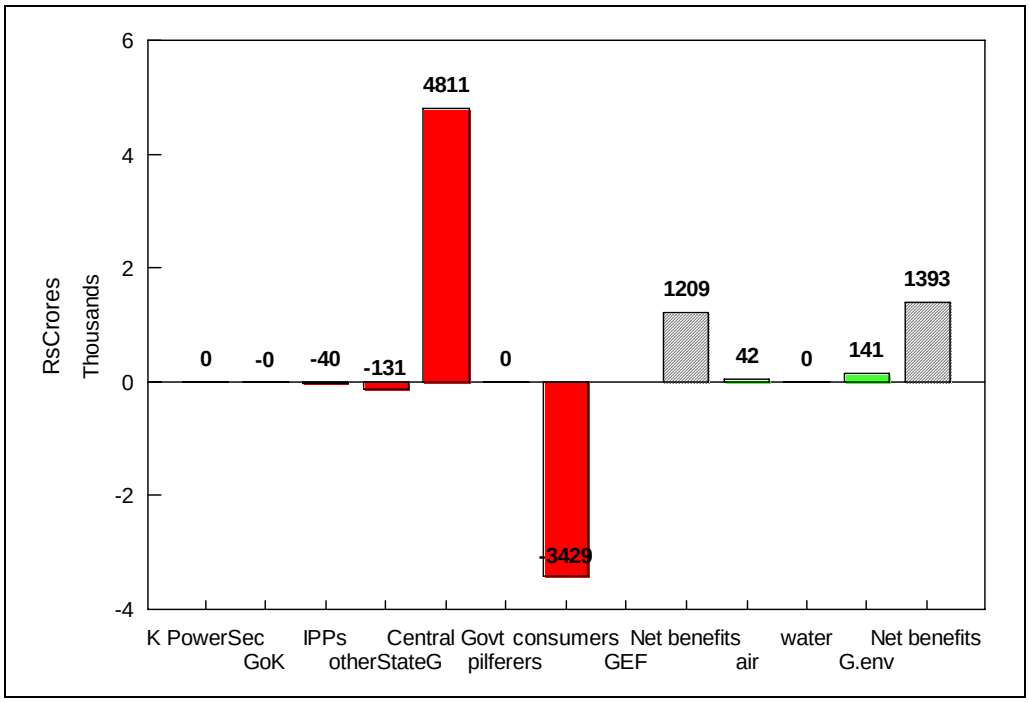


8.9 As part of the announced deal between KPTCL and the developers, realized carbon benefits such as those from projects undertaken under the Clean Development Mechanism of the Kyoto Protocol will need to be passed to consumers. However, even at US$15/ton, the expected revenue of Rs 0.54 billion would not offset the Rs 3.16 billion of consumer losses.

Imported Coal at West Coast Locations

8.10 The high rate of customs duty imposed on imported coal means that domestic coal would be used at west coast locations, as this would be least-cost in financial terms from the perspective of Karnataka's electricity users. The impacts on the stakeholders are as shown in Figure 8.6.

Figure 8.6: Impact of Imported Coal (Under Current GoI Customs Duty)



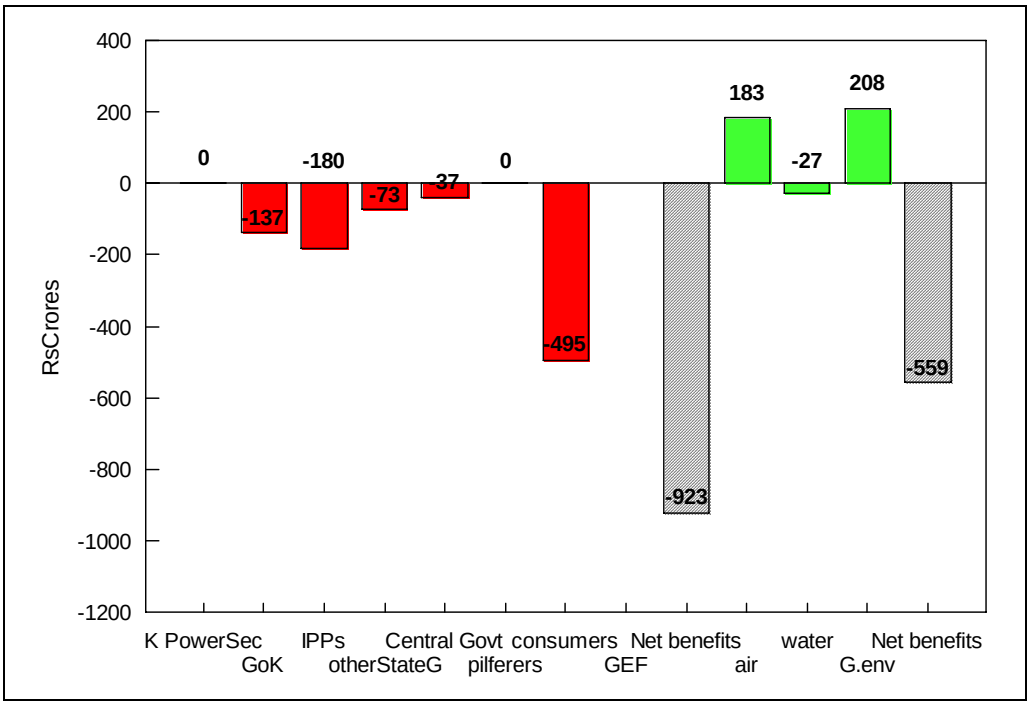
8.11 We conclude that:

- Imported coal at west coast locations is economic, offering also gains for the environment.
- Consumers lose because high customs duty increases the cost of coal generation. The GoI gains from the high collection of customs duty.
- Customs duty prevents realization of the least-cost option for Karnataka. Even without the additional environmental benefits, the foregone benefit (as NPV) is Rs 12.09 billion.

Natural Gas

8.12 To evaluate the natural gas option we assume that Karnataka will benefit from the new gas fields recently discovered off the coast of Andhra Pradesh, based on the assumption that a major gas pipeline will deliver this gas to AP, Karnataka, and Maharashtra. The impacts on the stakeholders will be highly dependent on the natural gas pricing policy of the GoI. If, as is currently intended, natural gas is priced at the equivalent of a basket of fuel oils tied to international prices, then natural gas from the new Godaveri Basin finds (and set against the alternative of domestic coal) would not be economic for Karnataka (see Figure 8.7).

Figure 8.7: Impact of Natural Gas

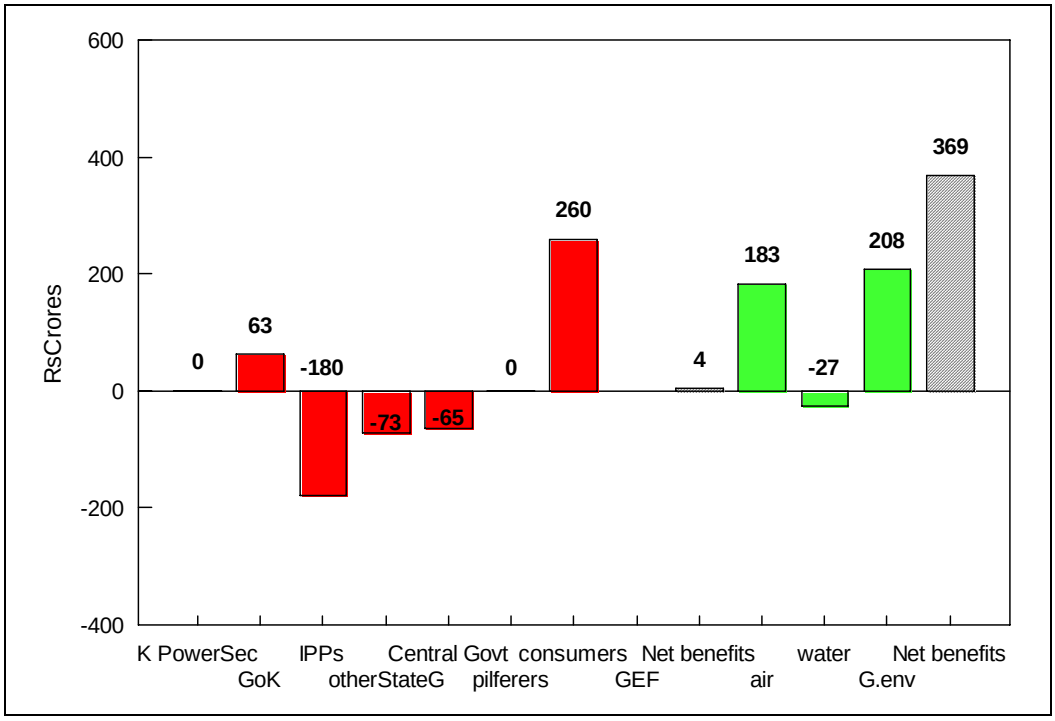


8.13 We conclude that:

- As expected, large local and global environmental benefits arise as gas replaces coal. These environmental benefits are not sufficient to offset the economic losses.
- Private sector IPPs appear to lose because natural gas plants have low capital investment (Table 3.10) and, since the assumption is that IPPs make a return on equity, plants of lower capital cost mean less equity return, in absolute terms.
- There is a small increase in Karnataka's consumptive water use, because the gas plants are assumed to be located in northern Karnataka along the gas pipeline and assumed to use CCCT technology, which requires water for cooling the steam turbine cycle. While this water consumption is smaller than the consumption that would be due to coal plants it is greater than the that of coastal projects, which would use seawater for cooling and therefore would have no consumptive fresh water use.

8.14 For gas to be economic (under the announced gas pricing policy) requires an oil price of around US$18/bbl. At this level, there is a small economic benefit to Karnataka of Rs 40 million (see Figure 8.8).

Figure 8.8: Impact of Natural Gas (US$1/bbl World Oil Price)

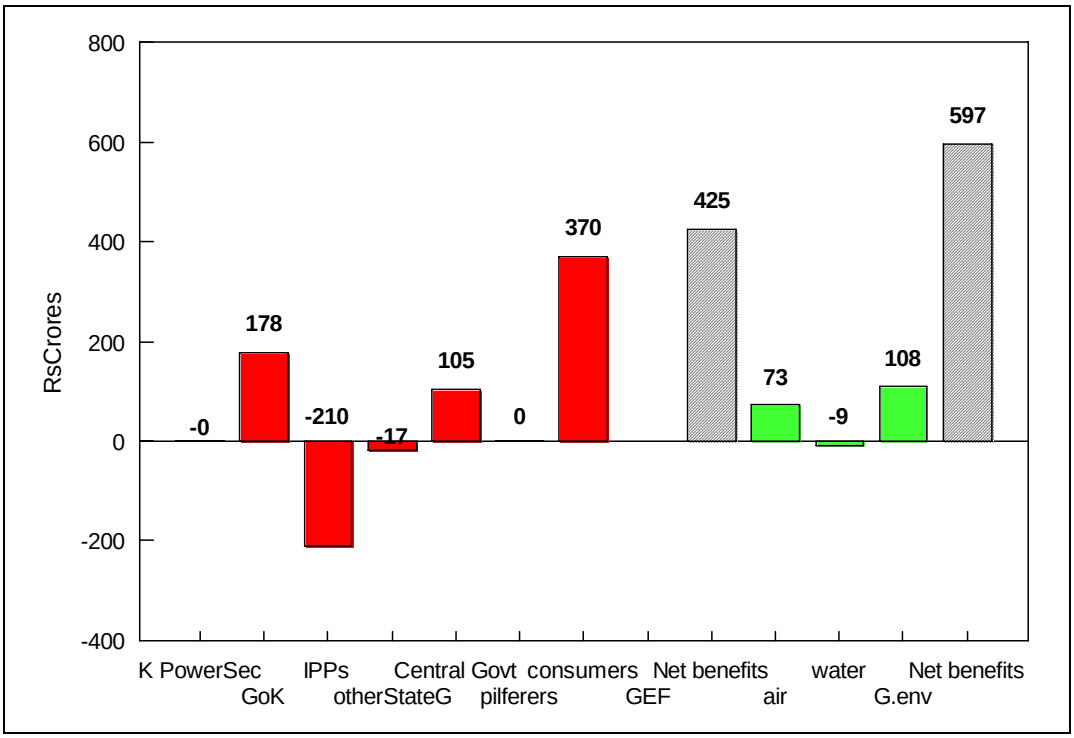


8.15 Imported coal would bring far larger benefits to Karnataka were the 29.5 percent customs duty to be removed. The fuel pricing policy of the GoI is inconsistent: if India's natural gas is to be priced on the basis of international prices, then why not also coal? In Karnataka's case, the high import duty effectively precludes the use of imported coal and prevents the economically least-cost solution from being implemented.

Krishna River Hydro Scenario

8.16 This scenario assumes that the Krishna water dispute is settled among the parties and that the Almatti Dam may be operated at the originally planned elevation of 524.24 meters. This would enable implementation of several downstream projects, including the cascade of run-of-river plants at Tammankal and the Jurala project (with the power generated shared equally with Andhra Pradesh). This is not likely in the short term, but it remains attractive because the environmental costs associated with resettlement and relocation (R&R) are small, since Tammankal is run-of-river; because the Jurala dam is already built, needing only a powerhouse; and because most R&R costs at Almatti (primarily due to the relocation of Bagalkot) are required in any case to achieve the lesser operating height at of 519 meters. The impacts on stakeholders are as shown in Figure 8.9.

Figure 8.9: Impact of the Krishna Hydro Development Scenario



8.17 We conclude that implementation of these hydro projects is beneficial to all except IPPs:

- IPPs lose, because the hydro projects are assumed to be built by KPCL and the equity returns captured by the GoK. Some of the additional returns to the GoK may be required by the Regulatory Commission to be passed on to the consumer, through lower tariffs.
- There are net economic benefits of Rs 4.25 billion to Karnataka, even without consideration of the environment.
- There are significant air emission environmental benefits (specifically, avoided fossil fuel emissions, including GHGs), increasing the net economic benefits to Rs 5.97 billion.

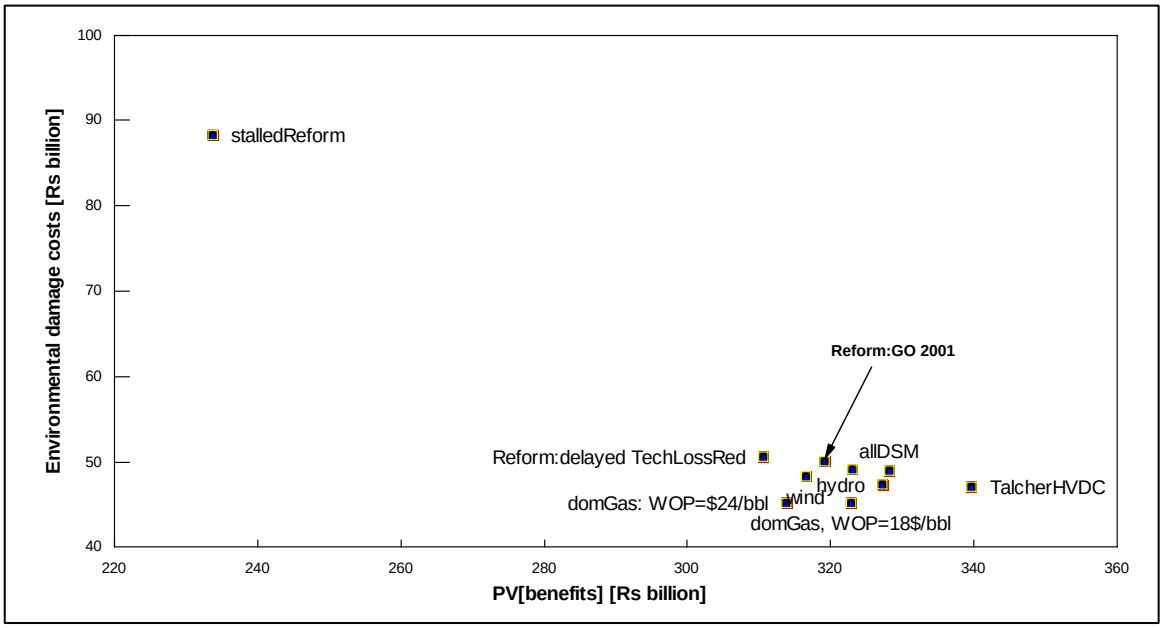
8.18 These results do not generalize to other hydro projects, particularly not to hydro projects in the Western Ghats. The Upper Krishna hydro projects are unique in that the main environmental and social impacts associated with the Almatti and Naraynpur dams are sunk (because the dams are built) and hence excluded from this analysis.

General Conclusions

The Importance of Power Sector Reform

8.19 This study permits a number of conclusions about the long-term environmentally sustainable development of the Karnataka power sector. The first, which is self-evident from Figure 8.10, is that of all the options studied, by far the worst outcome for environmental damage costs is stalled reform—which is greater by a factor of about 2.5. The variations in environmental damage costs across the various options, from DSM to wind to the HVDC import option, pale in comparison to the increase in environmental damage costs that follow failure to reform as planned.

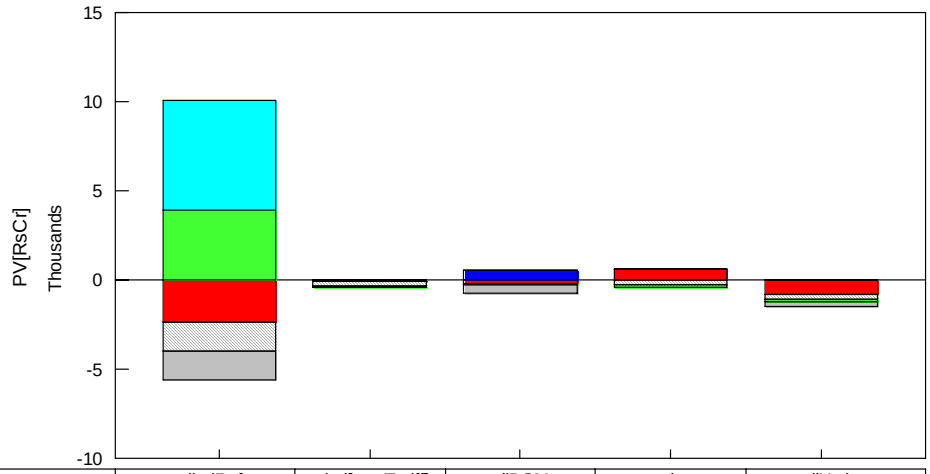
Figure 8.10: Environmental Damage Costs in Karnataka Versus Net Economic Benefits (Excluding Environmental Damage Costs) (as NPV in Rs 10 millions)



8.20 Stalled reform has by far the lowest economic benefits as well as by far the highest environmental damage costs: Power sector reform is thus a classic win-win strategy, for both economic development and the environment.

8.21 Figure 8.11 shows how much greater are the changes in the cost structure of the power sector under stalled reform than for other options. Bars above the line in this chart represent increases in costs and bars below represent decreases in costs: if reform stalls and IPPs cannot reach financial closure there would be significant reductions in generation and T&D investments. These would be outweighed, however, by the far larger decreases in benefits.

Figure 8.11: Changes in Cost Structure—Stalled Reform Versus Selected Other Options



	stalledReform	wind[newTariff]	allDSM	nuclear	smallHydro
generation costs	-2374	-87	-174	598	-779
fuel	-1629	-209	-53	-286	-267
DSM	0	0	571	0	0
Env.Damages	3906	-86	-17	-123	-149
T&D investments	-1606	-0	-478	0	-268
Self-gen	6155	0	0	0	0

DSM

8.22 DSM in the tariff-subsidized sectors is clearly win-win, but an additional reason for advocating DSM programs is that the policy initiatives required are entirely within the control of Karnataka. There are other attractive win-win options, but for these to materialize requires decisions by others and technology developments elsewhere. The gas pipeline from the Godaveri Basin to Bombay may or may not pass through northern Karnataka, for example, and its timing is uncertain. Wind power capital costs may or may not decrease, but the rate of decrease would not in any case be dependent upon the extent to which Karnataka adopts wind power, since decreases in wind capital costs will follow from the global market for wind power. The Krishna hydro development may be win-win, but it is subject to the unpredictable actions of downstream riparians, and river basin planning of the Krishna is opposed both by Andhra Pradesh and Maharashtra. DSM, however, is dependent upon no such risk factors, and could be implemented immediately as a state program.

Annex 1

Attribute Value Table

Annex I: Attribute Value Table

	Economic efficiency		Supply quality	Govt Impact	Tariff	Local air emissions			Consumptive water use	GHG emissions	
	Net economic benefits	Average incremental cost, AIC	GWh of unserved energy	Net fiscal transfer	average levelized	NO_x	SO_x	PM10		undisc.	discounted
	NPV		NPV	NPV		NPV	NPV	NPV	NPV		NPV
	[Rs millions]	Rs/kWh	[GWh]	[Rs millions]	[Rs/kWh]	[1000t]	[1000t]	[1000t]	[billion gallons]	[mt]	[mt]
Reform baseline (GO 2001)	323,010	3.03	0	-39,790	2.75	422	516	110	159	159	46
Stalled reform	233,770	3.54	26433	-97,740	2.77	434	518	115	164	142	44
E Act	329,450	3.09	0	-36,160	2.73	433	530	113	164	164	47
Max hydro	327,260	2.97	0	-38,010	2.73	401	505	108	161	151	44
Nuclear	319,900	3.07	0	-39,660	2.74	413	506	108	164	153	45
Domestic gas: (WOP=US$24/bbl)	313,780	3.20	0	-52,160	2.78	408	469	100	165	140	43
Domestic gas, (WOP=US$18/bbl)	322,930	3.06	0	-36,160	2.74	408	469	100	165	140	43
Imported coal	335,100	2.85	0	-39,790	2.91	418	481	109	159	147	44
Imported coal + FGD	331,040	2.91	0	-38,080	2.95	418	443	109	159	149	44
Talcher HVDC	339,730	2.81	0	-44,170	2.68	418	520	109	159	142	43
All DSM	328,190	3.07	0	-38,240	2.74	417	516	110	159	159	45
Delayed NT loss Red.	319,100	2.95	0	-44,790	2.82	433	523	112	162	163	47
Delayed tech loss Red.	310,620	3.22	0	-46,070	2.83	440	526	112	163	165	47
Bagasse	329,580	2.89	0	-38,730	2.70	403	491	105	162	152	44
Small Hydro	322,850	3.01	0	-39,570	2.75	403	501	107	160	154	44
wind[newTariff]	316,620	3.12	0	-43,240	2.78	414	509	109	157	155	45

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