ENERGY TECHNOLOGY INNOVATION POLICY

A joint project of the Science, Technology and Public Policy Program and the Environment and Natural Resources Program
Belfer Center for Science and International Affairs

HARVARD UNIVERSITY

JOHN F. KENNEDY SCHOOL OF GOVERNMENT

Cleaner Power in India: Towards a Clean-Coal-Technology Roadmap

ANANTH P. CHIKKATUR
AMBUJ D. SAGAR

Discussion Paper 2007-06
December 2007

Cleaner Power in India:
Towards a Clean-Coal-Technology Roadmap

Ananth P. Chikkatur* and Ambuj D. Sagar

(ananth_chikkatur@harvard.edu, asagar@seas.harvard.edu)

Energy Technology Innovation Policy
Belfer Center for Science and International Affairs
Kennedy School of Government, Harvard University
79 John F. Kennedy Street
Cambridge, MA 02138
USA

* Corresponding author

Belfer Center Discussion Paper 2007-06
December 2007

Citation

This paper may be cited as: Chikkatur, Ananth P. and Ambuj D. Sagar, “Cleaner Power in India: Towards a Clean-Coal-Technology Roadmap.” Discussion Paper 2007-06, Cambridge, Mass.: Belfer Center for Science and International Affairs, December 2007.

Comments are welcome and may be directed to Ananth Chikkatur at the Belfer Center, Kennedy School of Government, Harvard University, 79 JFK Street, Cambridge, MA 02138.

Energy Technology Innovation Policy

The overarching objective of the Energy Technology Innovation Policy (ETIP) research group is to determine and then seek to promote adoption of effective strategies for developing and deploying cleaner and more efficient energy technologies, primarily in three of the biggest energy-consuming nations in the world: the United States, China, and India. These three countries have enormous influence on local, regional, and global environmental conditions through their energy production and consumption.

ETIP researchers seek to identify and promote strategies that these countries can pursue, separately and collaboratively, for accelerating the development and deployment of advanced energy options that can reduce conventional air pollution, minimize future greenhouse-gas emissions, reduce dependence on oil, facilitate poverty alleviation, and promote economic development. ETIP's focus on three crucial countries rather than only one not only multiplies directly our leverage on the world scale and facilitates the pursuit of cooperative efforts, but also allows for the development of new insights from comparisons and contrasts among conditions and strategies in the three cases.

Acknowledgements

The authors are grateful for the financial support, through Harvard Kennedy School's research group on Energy Technology Innovation Policy, from the David & Lucile Packard Foundation, the Winslow Foundation, the William and Flora Hewlett Foundation, a gift from Shell Exploration and Production, and general support grants from BP Alternative Energy and Carbon Mitigation Initiative.

This paper draws upon discussions and interviews with a large number of experts from government agencies, manufacturing companies, utilities, coal companies, international and bilateral organizations, NGOs, and academia in India and the United States. We sincerely appreciate them sharing generously their time and insights on the Indian coal power sector. We are grateful to them all.

We would like to thank Robert Frosch, Henry Lee, and Robert Williams for their through reading, detailed comments and constructive suggestions on improving an earlier version of this paper. We appreciate Tim Conant of the Kennedy School Library for going above and beyond the call of duty in tracking down and procuring key references. Of course, the final responsibility for the paper, and the interpretations offered therein, lies with us.

EXECUTIVE SUMMARY

Availability of, and access to, electricity is a crucial element of modern economies and it helps pave the way for human development. Accordingly, the power sector has been given a high priority in the national planning processes in India and a concerted focus on enhancing this sector has resulted in significant gains in generation and availability of electricity in the years since independence.

Coal-based power has driven much of the growth in India's power sector over the past three decades. By 2004-05, coal and lignite accounted for about 57% of installed capacity (68 GW out of 118 GW) and 71% of generated electricity (424 TWh out of 594 TWh) in the country; currently, the power sector consumes about 80% of the coal produced in the country. As the demand for electricity is expect to rise dramatically over the next decade, coal will continue to be the dominant energy source. The Central Electricity Authority (CEA) has estimated that meeting electricity demand over the next ten years will require more than doubling the existing capacity, from about 132 GW in 2007 to about 280 GW by 2017, of which at least 80 GW of new capacity is expected to be based on coal.

Sub-critical pulverized coal (PC) combustion power plants manufactured by Bharat Heavy Electricals Limited (BHEL) – based on technologies licensed from various international manufacturers – have been the backbone of India's coal-power sector. Although the unit size and efficiency of these BHEL-manufactured power plants have steadily increased, the basic technology has not changed much. Internationally, however, there is now a range of advanced, more efficient, and cleaner technologies for producing electricity using coal. Combustion based on supercritical steam, offering higher efficiencies than sub-critical PC, is a commercial technology. Ultra-supercritical PC, which offers even higher efficiency, is also being deployed, while oxy-fuel combustion for facilitating capture of carbon-dioxide (CO_2) is under development. Integrated gasification with combined-cycle operation (IGCC), with significant potential for high efficiency and for cost-effective reduction of CO_2 and other emissions, is likely to be commercially available in the near future.

Therefore, even as India stands poised on the edge of significant growth in coal power, it is critical to promote technology trajectories that not only meet the near-term needs of the country but also set the coal-based power sector on a path that would allow it to better respond to future challenges. Current policies in the power sector are primarily driven by the need to increase generating capacity, which has had the result of deploying the least risky and cheapest technology (subcritical PC). On the other hand, growing international and domestic concern about limiting carbon emissions from the power sector has implicitly pushed the debate on technologies towards deployment of IGCC in India. However, such technology choices cannot be made blithely; today's decisions about power plant technologies will have consequences over the plant's entire lifetime – a period of about 40-60 years. Therefore, an explicit focus on technology policy in the coal power sector is imperative in order to ensure that any technology decisions are made with deliberate care.

In an evolving technology landscape, it would be risky to pick technology winners *a priori*, and hence, a systematic and objective analysis of emerging technologies is required, keeping in mind India's historical trajectory and its current and future needs, challenges and constraints. Such an analysis can be a foundation for developing consensus on an appropriate technology roadmap for the country, as well as on an innovation strategy to help implement such a roadmap. This paper aims to contribute to such a planning process by assessing technology options in the Indian context, and offers suggestions towards developing a coal-power technology roadmap for India.

The key challenges facing India's power sector include: an urgent need to increase energy and electricity availability for human and infrastructure development; increasing energy security; local environment protection and pollution control; and control of greenhouse gas emissions (particularly carbon dioxide). The task of meeting these broad challenges is further complicated by several constraints: availability and quality of domestic coal; limited financial resources; inadequate technical capacity for R&D, manufacturing, and O&M; and the institutional characteristics of the Indian power sector. Based on a broad vision of 'expanding power generation at low cost while enhancing India's energy security and protecting the local and global environment' we assess, using a ranking scheme, various coal combustion and gasification technologies on a number of key dimensions for the present and for the short-to-medium-term future (~10 years).

Our analysis suggests that commercial supercritical combustion technology is the best option for India in the short-to-medium term. While gasification and advanced combustion technologies will be potentially important options for the longer-term future, there are significant issues surrounding the current relevance of these emerging technologies for India, including uncertainties in technical and cost trajectory, suitability for Indian conditions, and timing of India's greenhouse-gas mitigation commitments. Given the still evolving (technical and deployment) nature of many of the key technologies, our analysis suggests that India should not make rigid technology choices for the long term, but rather keep its options open. We have also developed an illustrative technology roadmap for the India's coal-power sector, along with key policies to help implement the roadmap:

(a) improve the efficiency of the power system (generating stock, T&D network, and end-use sectors) to reduce the need for addition in generation capacity and therefore buy time for making appropriate technology decisions;
(b) implement supercritical-combustion-based generation plants to meet capacity addition needs in the short-to-medium term;
(c) evaluate on an ongoing basis the appropriateness of emerging technologies for India through a monitoring and feasibility assessment program, and by advancing specific elements of these technologies and ensure that they can be deployed as and when needed through a strategic research, development, and demonstration program, in partnership with key actors from the coal and hydrocarbon mining, and the petrochemical industry;

(d) enforce and tighten local environmental pollution controls through better pollution control technologies and greater and meaningful public participation; and
(e) invest in a focused plan to examine geological carbon storage options, with detailed assessment of CO_2 storage locations, capacity and storage mechanisms in order to collect valuable information for India's carbon mitigation options and inform future technology selection as well as siting decisions for coal-power plants.

We believe that a 'no-regrets' approach of this kind will keep appropriate options open and help make better technology choices as more information becomes available in the future. Furthermore, implementation of a technology roadmap and the 'no-regret' policies discussed above will be facilitated by several broader activities and programs. Some of the key activities include better understanding and use of coal resources and improving coal sector institutions, improving the institutional and financial health of the power sector, better inter-ministerial and regulatory coordination, improving systems of technology and policy innovation, systematic and coherent domestic energy policy analysis, and international action and cooperation on climate change mitigation.

Although the roadmap and the implementation program presented in this paper are meant to be illustrative (rather than definitive), many aspects of the policy elements and facilitating conditions will hold regardless of the specifics of the final roadmap. Our roadmap and the policy suggestions are intended to catalyze discussions on the technology path forward for the coal-power sector. We also hope that it will serve as a foundation for a formal roadmapping process which brings together appropriate stakeholders (including government planners, key ministries, private and public sector utilities and manufacturers, financial institutions, employee unions, academia, and NGOs) and engage them in productive discussions aimed at developing a consensus roadmap that serves the country's needs. In fact, it must be emphasized here that a successful outcome of a roadmapping exercise and its implementation are very much dependent on the underlying process. Generating utility-scale electricity from coal requires a range of tradeoffs – financial, natural resource, environmental, and social – and there is a diverse set of stakeholders who have strong concerns about decisions made in this sector. Our belief is that the Planning Commission of India may be the best body to facilitate these discussions, given its relative 'neutrality' and its existing broad analytical base on power sector issues.

While it is important for the government to lead such a roadmapping exercise, a transparent and inclusive process must aim to build consensus among stakeholders on a range of key issues. Hence, the roadmapping process must ensure outcomes that are consistent with the country's agreed-upon developmental priorities, and also acceptable to the local populace whose lives will be directly affected by building large coal power plants. This will go a long way in advancing the long-term strategic technology policies and planning in the sector and assist the decision-making process for developing and deploying advanced coal-power technologies. Finally, the roadmapping process will also help consolidate the existing coal-based R&D programs in industry, research institutes, and academia under a common vision with specific objectives and plans for the future, and help make appropriate international linkages.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

1 Introduction

Electricity, as an energy carrier, has revolutionized our modern world. It not only helps provides a range of services – lighting, refrigeration, communication, etc. – that are critical to human development but also underpins modern industrial production and thereby add significantly to economic development. There is a broad correlation between consumption of electricity and human development, and, in fact, the availability and access to electricity often is considered as one of the indicators of national development, including in India (IAEA et al., 2005; World Bank, 2007). Accordingly, the power sector has occupied a place of prominence in national planning processes in India and a concerted focus on enhancing the power sector has resulted in significant gains in generation and availability of power. While large-scale electricity generation was introduced to India during the British occupation just before the turn of the century in 1897,[1] by 1950, the installed capacity and the annual electricity generation in the country had reached only 1.7 GW and 5.1 TWh, respectively. By the end of March 2005, the installed capacity of utilities is 118 GW,[2] generating about 594 TWh (CEA, 2006a). Although this growth is impressive, far more still needs to be done.

Electricity availability India still falls far short of the global benchmarks – in 2004, per-capita consumption was 457 kWh, in contrast to the global average of 2500 kWh and the OECD average of 8200 kWh (IEA, 2006b) – and the country's power sector lags behind most other industrializing countries.[3] Lack of power availability is widely seen as a bottleneck to industrial development, especially if the country is to maintain the pace of economic growth seen in recent years (annual real GDP growth of more than 6% over the past decade[4]).

Furthermore, there remain a range of issues relating to access to electricity in the country. According to IEA, nearly 580 million people did not have access to electricity in India even in 2000 (IEA, 2002b). Availability of, and access to, clean energy (such as electricity) for lighting and small-scale industrial activities is an important element of increasing economic and social

---

[1] The 130 kW Sidrabong hydro-electric power plant in Darjeeling was the first large-scale utility in the country. The first large commercial steam-powered station was the Calcutta Electricity Supply Corporation's one MW generator, which began operations in 1899 This station at Emambaugh Lane had three Babcock and Wilcox boilers combined with Willans engines and Crompton dynamos ((Ray, 1999) and http://cesc.co.in/php_cescltd/aboutus/history/main.php).

[2] Utilities are electricity generating companies whose electricity is mostly distributed to the general public. Utilities can be owned by either the public or private sector. According to the latest data, by March 31st 2007, the installed capacity in utilities was 137 GW (CEA, 2007a). In contrast, electricity from captive power generators is consumed internally. Captive power plants are usually put up by industries (steel, paper, cement, fertilizer, sugar, etc.). Including captive power, all India installed capacity in 2004-05 was 137.5 GW, generating about 666 BU (CEA, 2006a).

[3] For example, while the development of the power sector in India has been significant, China has seen even more substantial gains. In 1971, Indian power generation was 60.9 TWh (per-capita consumption 99 kWh) while Chinese power generation was 138.4 TWh (per-capita consumption 151 kWh); in 2004, these numbers were 667.8 TWh (per-capita consumption 457 kWh) and 2199.6 TWh (per-capita consumption 1585 kWh). As a reference, the 2004 average per-capita consumption in non-OECD countries was 1240 kWh (World Bank, 2005; IEA, 2006b).

[4] The average GDP growth from 1995-96 to 2004-05 was 12% in current prices and 6.2% in constant 1993-94 prices (Ministry of Statistics and Programme Implementation).

development for the poor.[5] There is also a strong disparity in electricity access and consumption between urban and rural areas – about 56% of households in rural areas do not access to electricity, in contrast to only 12% in urban areas[6] and urban consumers consume about 3.5 times more electricity on average than rural consumers (TERI, 2004).[7] At the same time, the country has been routinely experiencing power shortfalls of 6-12% and shortages of peak demand between 11-20% over the last decade.[8]

In order to resolve these issues, the Government of India has announced that 100 GW of new capacity needs to be installed in the 10th and 11th plan periods (2002-2012) to meet its goal of providing "reliable, affordable and quality power supply for all users by 2012" (Ministry of Power, 2001). Longer-term scenarios indicate that an installed capacity of nearly 800 GW by 2030 is necessary to sustain an average annual GDP growth of 8% (Planning Commission, 2006).

Historically, coal and water were the primary resources used for electricity generation in the country, but since the 1970s, fossil-fuel-based power plants have dominated the electricity sector.[9] By March 2005, coal plants constituted 57% of installed capacity, while generating about 71% of electricity supply in the country (CEA, 2006a). Accordingly, these plants consumed about 279 million tons of coal and 25 million tons of lignite in 2004-05 (CEA, 2006a), making the power sector the largest consumer of domestic coal – about 80% of coal produced in 2004-05 was sent to power plants (Ministry of Coal, 2006). This domination of coal in the power sector (and vice-versa) is likely to continue in the future. According to the Working Group for the 11th Plan (CEA, 2007b), about 46.6 GW of new coal-based capacity is expected to be installed by 2012 (which is about 68% of total planned addition of 69 GW).[10] Coal requirement for these new plants is projected to about 545 MT. Long-term scenarios from the Planning Commission (2006) suggest that annual coal consumption by the power sector might range between 1 to 2 billion tons by 2030.

While there is widespread consensus that coal will continue to play a central role in the country's electricity future, there has not been enough discussion of the specific technologies that these power plants should use. In addition to meeting the goal of rapidly expanding power generation, a number of immediate and future challenges will influence the direction of the coal-power sector. At the same time, there are now a number of different existing and emerging technological options that potentially can help the coal power sector meet its goal of rapid capacity addition in a manner consistent with its other challenges. Yet, it is not clear which of these options might be most relevant for the country. Thus, there is an urgent need to assess the suitability of these various technological options for the Indian context and to make appropriate choices in the context of existing and anticipated future challenges. This, in turn, requires

[5] India has the largest fraction (~1/3) of the world's poor – in 2001, about 360 million living with less than a $1 a day and 830 million with under $2 a day (Planning Commission, 1952).
[6] Census of India, 2001. http://www.censusindia.net/2001housing/S00-019.html.
[7] This urban-rural disparity is greatest in poor states such as Bihar, where urban-to-rural ratio is 15:1.
[8] Various Annual Reports of Ministry of Power.
[9] Fossil fuel drives much of the world's electricity. Nearly 65% of the world's electricity is currently generated with fossil-fuels (IEA, 2004c).
[10] Furthermore, another 82 GW of total additions is projected for the 12th Plan, of which nearly 40 GW is expected to be thermal capacity (CEA, 2007b).

systematic and careful technology analysis and decision-making. This situation is very different from the past when only one particular technology option – sub-critical pulverized coal – dominated the global technology landscape and the focus in the Indian coal power sector was mainly on adaptation and multiplication of the technology rather than choosing between widely disparate options.

This paper makes an argument for a technology planning process – technology roadmapping – that is particularly relevant for the Indian coal-based power sector. We begin by briefly reviewing the historical technology decision-making in the coal power sector before discussing what we consider as the most important future challenges and constraints faced by this sector. Key challenges include the need for rapid growth to meet development needs, for ensuring greater energy security, and for cleaner power generation including limiting emissions of carbon-dioxide. Constraints include uncertainties regarding coal quantity, poor coal quality, limited financial resources and technical capacity, and institutional limitations. We then highlight the need for policies related to energy technology in general and then argue for a systematic technology roadmapping process as a possible approach to facilitate the complex decision-making facing the coal-power sector. Next, the current status and projected development of advanced technologies are described and compared with each other, including their applicability in the Indian context. Finally, we outline, based on our own technology assessment and analysis, an illustrative technology roadmap for the Indian coal sector. We note that this last exercise is not intended to develop a definitive roadmap (although we will focus on specific possibilities) but more to serve as an illustration of, and stepping stone towards, a formal roadmapping process. We end by highlighting appropriate enabling conditions and the next steps needed to develop and implement such a roadmap for the country.

2 Historical drivers and technology decisions in the Indian coal-power sector

The history of the Indian power sector can be roughly divided into four phases – 'pre-independence' (1900s-1940s), 'public-sector dominance' (late 1940s-to-mid-1970s), 'rise of coal' (mid-1970s-to-1990), 'liberalization and reforms' (1991-to-early-2000s). The present phase can be termed as 'beyond Electricity Act 2003'. A graphical illustration of the growth of the power sector is shown in Figure 1, 2, and 3.

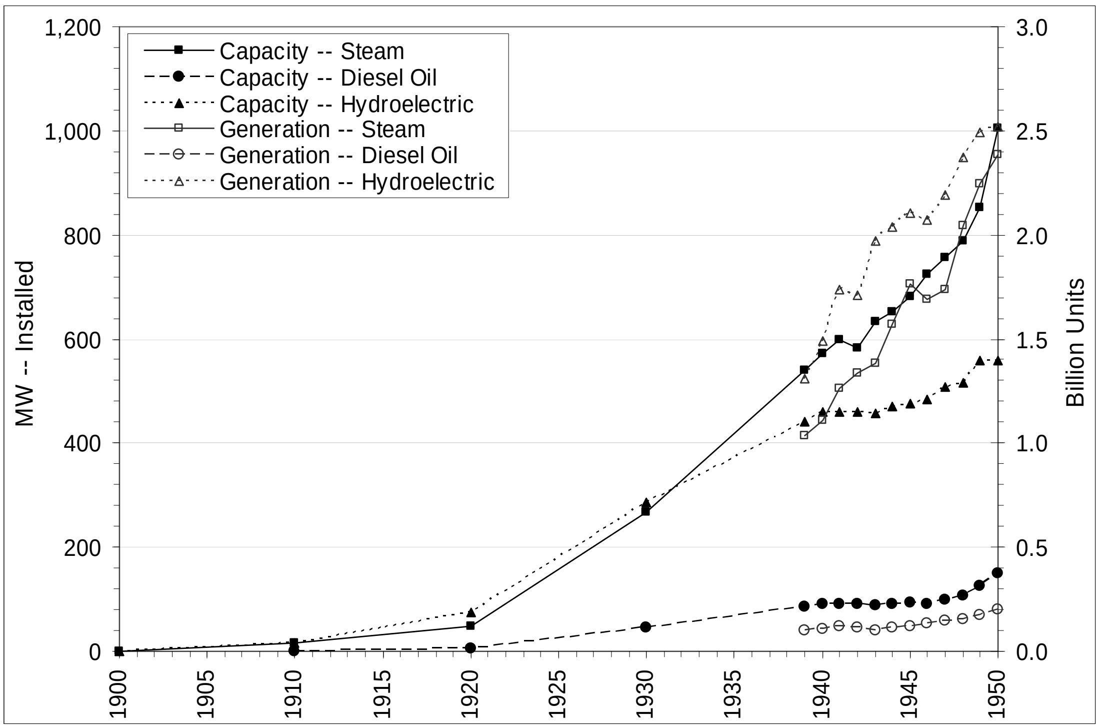

Figure 1: Installed capacity in the Indian power sector (1900-1950). The installed capacity (left-axis) for coal-based steam (closed rectangles), hydroelectric (closed triangles), and diesel (closed circles) plants are shown. Generation data (right axis) is shown from 1939 onwards in respective open symbols. Sources: (CWPC, 1955) for data between 1900 to 1930 and (CWPC, 1951) for data between 1939 to 1950.

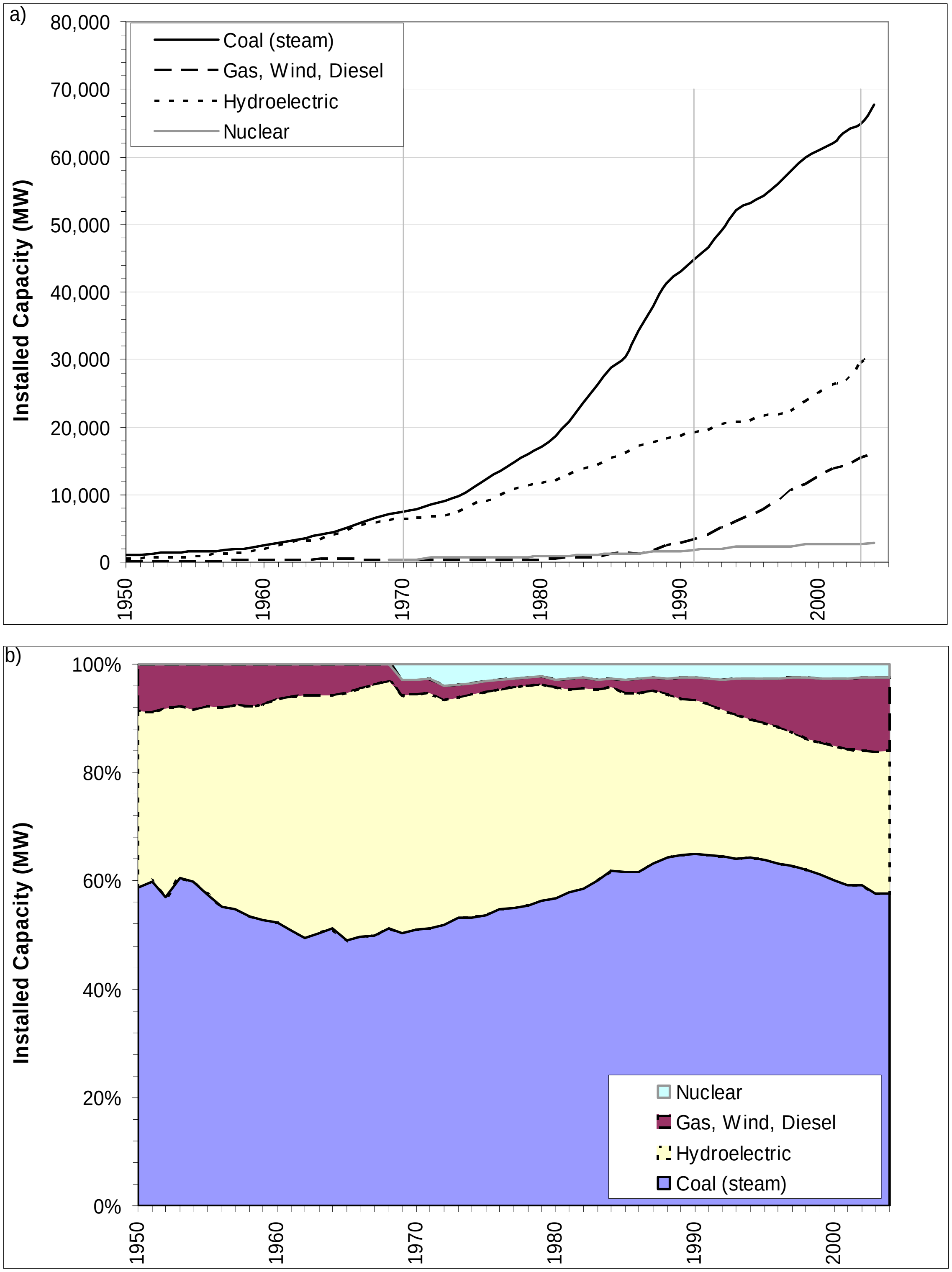

Figure 2: Installed Capacity (1950-2003). Installed capacity both in MW (a) and in percentage (b) is shown for steam (coal), hydroelectric, nuclear and gas, wind & diesel plants. Source: CEA's All India Electricity Statistics: General Review (various years).

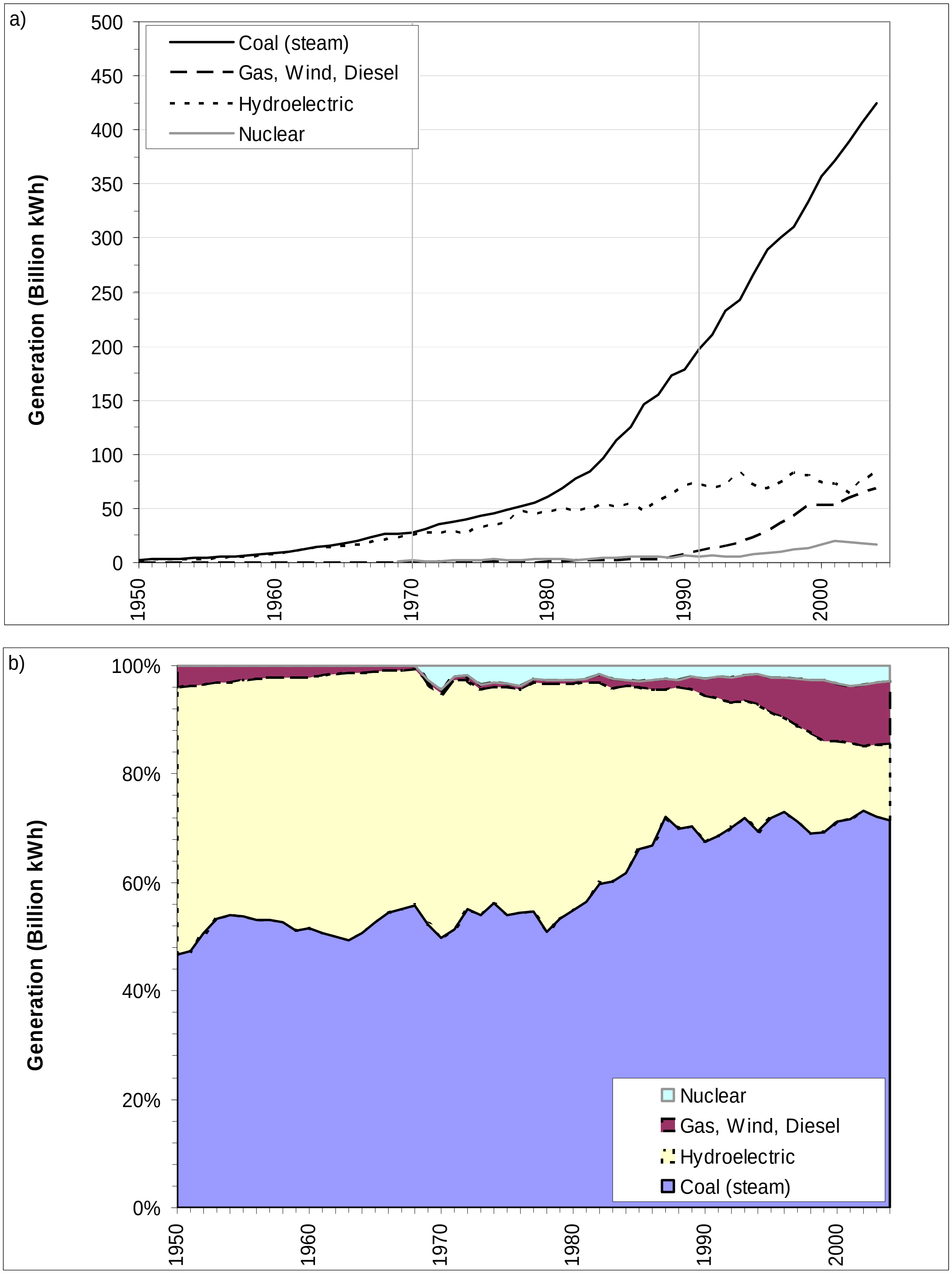

Figure 3: Generation of Electricity (1950-2004). The generation of electricity both in kWh (a) and as a percentage of total (b) is shown for steam (i.e., coal), hydroelectric, nuclear and gas, wind & diesel plants. Source: Same as Figure 2.

2.1 Pre-independence (1900-1947)

Utility-scale electricity production began in India relatively early in comparison to other developing countries because India was a British colony. Although initially considered a luxury item, electricity soon became a powerful force for development through mechanized industrialization.[11] Most of the installed capacity was located in West Bengal and Bombay states which were under strong British influence and contained major urban and industrial areas.[12] The key driver for electricity growth was demand by industries, tramways, commercial enterprises, and domestic use. Hence, coal-fired and hydro-electric power plants were installed to meet this demand (see Figure 1)—the average annual growth rate was nearly 20% until 1940. By 1950, just after India's independence, there were 65 undertakings that generated electricity using coal-fired steam generators for public supply.[13] They produced 2.4 TWh of electricity with a total installed capacity of 1 GW, which was about 60% of total capacity[14] and 50% of total electricity generated (CWPC, 1951; Planning Commission, 1952).

During this period, the electricity sector was mainly in the private sector,[15] similar to the worldwide norm at that time. These private undertakings were held under British "holding companies" that provided management and finances to the undertakings. However, these holding companies were beholden only to their British stakeholders – for example, while the electricity undertakings were given generation licenses under the Indian Electricity Acts (based on similar British Acts), these Acts only provided safety guidelines and regulations for electricity generation and distribution and did not enforce stringent government control in this sector (Shah, 1949).[16] Other than the requirement for obtaining a license, the electricity sector was essentially unregulated. There was little interest in controlling the costs of power, leading to high costs attributed to high installation costs, defective planning,[17] financial manipulation of and profiteering by holding companies, necessity of technology imports, defective indigenous

[11] Shah (1949) has eloquently described the early recognition of the relationship between electrical power and industrialization: "Electrical energy is something more than a commodity; it is the very life blood of industrial nation which must flow abundantly and without interruption if the nation's strength and well-being are to be preserved."

[12] The demand in the major cities in these states, Calcutta and Bombay, consumed about 40% of the entire electricity generated in India by 1950 (CWPC, 1951; Planning Commission, 1952).

[13] In addition to the public utilities, there was about 588 MW of captive capacity in 267 industrial establishments, consisting mainly of coal and oil-fired units (Shah, 1949).

[14] The public utilities had a total capacity of 1.71 GW, of which 1 GW was based on coal, 0.56 GW using hydroelectricity and 0.15 MW using oil.

[15] Prior to the 1930s, all electricity undertakings were under the private sector, with the sole exception of the Sivasamudram hydro-electric plant built by the Mysore Maharaja in 1902 to produce electricity for the nearby Kolar gold fields (Planning Commission, 1952). In the 1930s and 40s, city municipalities and provincial governments began to build and own power stations, such that by 1950 only about 60% of the public utilities were owned by companies (Shah, 1949).

[16] The original draft of the Indian Electricity Act of 1903 was prepared by a British firm interested in electrical industry. (Shah, 1949)

[17] While many of the government-owned projects resulted in low-cost electricity, particularly the hydro-electric projects of Mysore and Madras Provinces, there were several poorly designed projects in United Provinces and Punjab that resulted in inefficient use of electricity and high-cost of generation that limited industrial growth in these areas (Shah, 1949). Shah (1949) even claims that these projects were mainly aimed at exporting foreign machinery and plants to India.

technical knowledge, and high cost of operations (Shah, 1949). In addition, there was little or no serious effort to increase load factors by promoting industrial growth[18] – in fact, the generation of electricity without proper assessment and development of load was a key complaint of many Indians against the British Government.

There was also no uniformity of supply – electricity was supplied in both AC and DC forms at varying voltages (CWPC, 1951) – and there was little cooperation or coordination between different suppliers (Rao, 2002).

2.1.1 Coal power technology (pre-independence)

Given India's lack of industrial development before independence, not only the technology for generating electricity, but also the materials and equipment necessary for construction, had to be imported. The earliest technologies[19] were directly imported from Britain and British engineers worked in India to install and train Indian counterparts in installation and operation of power plants.[20] The coal-fired boilers were of the *stoker water-tube* kind, where coal was burned on a grate, and the resultant hot flue gas was directed towards water-tubes, in which water was converted to high pressure and high temperature steam (Singer et al., 1958; Miller, 2005). The Babcock and Wilcox boilers used in the first coal-fired power plant in Calcutta (see footnote 1) were of this kind. Most of the units[21] installed in the 1940s were of sizes ranging from 1 MW to 15 MW, and they were designed to work with high quality coal, with calorific value greater than 6000 kcal/kg (CBIP, 1997). Stoker-fired boilers continued to be installed for utility power generation in India well into the 1960s, despite the availability of more advanced pulverized coal technology by this time.[22] The Calcutta Electricity Supply Company continues to operate stoker-fired boilers at its New Cossipore station, and another power station with stoker boilers was shut down only in December 2003 because of pollution problems.[23]

Thus, these various issues, particularly the emphasis on urban-centered power-sector development, the lack of indigenous manufacturing capacity and the laissez-faire attitude of the private sector and the British Government, hobbled and colored the post-independence power development of the country.

---

[18] In fact, Shah (1949) accuses the British Government of India holding back the country's industrial growth (effectively by not developing its power sector), so that the Indian industry did not compete with British interests. Instead, the government seemed to be content with promoting agriculture and agricultural industries (National Planning Committee, 1988).

[19] The electricity generation technology works, in essence, as follows: first, the carbon in coal is completely burned in a boiler and the generated heat is used to heat water/steam in tubes that encase the boiler. Then, the energy of the hot and pressurized steam is converted to rotary mechanical motion in a steam turbine. The rotating steam turbine, in turn, is connected to an electromagnetic generator that produces electricity. This combustion-based technology is still the most common technology in use.

[20] Shah (1949) notes that foreign experts, in some cases, were unwilling to share expertise and knowledge with their Indian counterparts. Furthermore, foreign engineers, who get their experience and practical knowledge in India, leave India at a period of life when their mature experience would be very useful to further development in the country.

[21] A power plant unit consists of consists of a boiler, a steam turbine, a generator and their auxiliary equipment.

[22] In the 1960s, several spreader stoker fired boilers were installed in Khaperkheda, Paras, Korba and Harduaganj; these boilers have all been phased out now (Subramanian, 1997).

[23] Indrani Dutta, "CESC Mulajore unit to be shut down by Dec", Hindu Business Line, May 28, 2003.

2.2 Rise of the public sector (1947-1970)

By the time of independence, the need for a rational development of the power sector through better laws that regulated electricity and reined in excessive private profits was well recognized. In fact, sixteen years prior to India's independence, the Indian National Congress had noted in its 1931 Karachi resolution that "real economic freedom of the starving millions" necessitates the State to "own or control key industries and services, mineral resources, railways, waterways, shipping and other means of public transport" (National Planning Committee, 1988). State ownership (public sector) and planning[24] became the key concepts for an independent India. Planning can essentially be defined as the state-determined means by which the use of available resources can be rationalized to meet stated objectives, in contrast to resource allocation determined by market forces.[25] Influenced by the Soviet socialist vision, the emphasis on public sector and planning in India was a strong (albeit not unique) post-colonial reaction to foreign rule where private (British) companies, particularly the East India Company, had ruled the roost for nearly 200 years.

Accordingly, the Indian Government created the National Planning Commission (NPC) and began its full-scale experiment of national-level economic planning with objectives of domestic self-sufficiency,[26] a rapid increase in the standard of living of the Indian people, decreasing economic inequality and poverty, and instituting a 'socialistic pattern of society'.[27] The National Plans aimed to promote self-reliant, autonomous development of the national economy, free of foreign capital, in which large-scale enterprises were to be state-owned.

Electricity was viewed as a crucial instrument for social development, and its rigid control by the government was considered essential for meeting the country's objectives.[28] Private companies were deemed to be ineffective for providing nation-wide access to electricity, since their profit motivation[29] would naturally lead them to focus on areas with greatest demand – cities and urban areas – and neglect rural areas where they would get meager return on their investments (Datta, 1961). Heavy concentration of electricity consumption in cities[30] was considered inequitable, and the government aimed its policies for providing cheap electricity to villages and rural areas

[24] Such planning was to include "cultural and spiritual values and the human side of life" in addition to economics and raising the standard of living (Dutt, 1990).
[25] Resource allocation through market forces was deemed to be disadvantageous to the poor since their demand is not adequately reflected in the market to give enough profit incentive to private producers to increase supply (National Planning Committee, 1988).
[26] The National Planning Committee noted that the principle objective of planning is to attain, as far as possible, national self-sufficiency and not primarily for purposes of foreign markets (Shah, 1949).
[27] A socialistic pattern of societal development depended on appreciable increases in national income and employment, whose benefits were to accrue more to those in the lower economic strata of society. Social gain and reduction of income and wealth inequality were considered more important than private profit that results in greater concentration of wealth and power.
[28] The entire enterprise of production as well as supply of electricity was to become a "Public Utility Concern" (Shah, 1949).
[29] In line with its socialistic tendencies, electricity for private profit was considered unacceptable and replaced by the principle of 'service before profit' (Planning Commission, 1952).
[30] In 1950, 56% of the total public utility installations served only about 3% of population in six large towns (Govil, 1998).

in order to increase electricity access and demand for irrigation and village-based small-scale industries (Planning Commission, 1952). It was hoped that a more uniform electricity supply across the country would result in greater equitable growth and development of the country. Per-capita consumption of electricity and the number of electrified villages became important metrics in the government's drive for equitable development. Furthermore, since electricity generation requires enormous up-front capital investment, government resources were considered necessary for increasing growth in the power sector (and thereby for the nation's development). Hence, significant fractions of the National Plan outlays were earmarked for the power sector (see Figure 4).

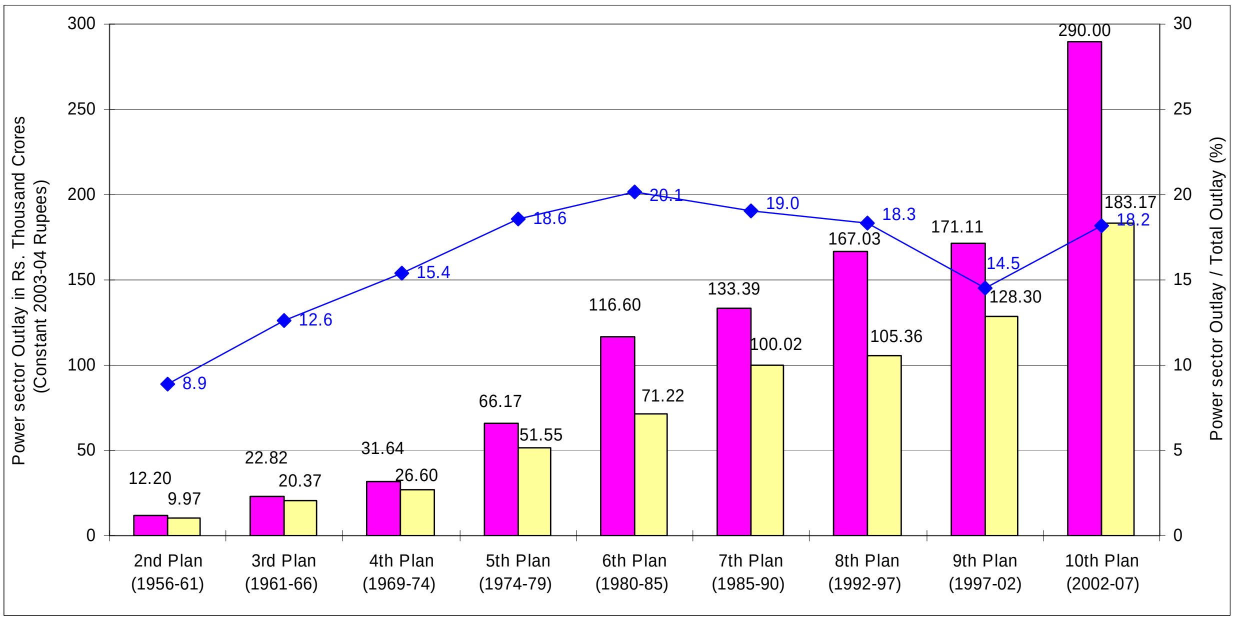

Figure 4: Power Sector Outlay and Expenditure. Five Year Plan outlay (dark bar) and expenditure (light bar) for the Power sector (left axis) and the power sector outlay as a fraction of the total Plan outlay (markers and line; right axis) are shown. The outlay is corrected to constant 2003-04 rupees based on GDP deflators (data from Central Statistical Organization) assuming that the planned outlay is given in rupees at the year preceding the Plan.[31] The expenditure is assumed to be given rupees at the last year of the Plan and converted to 2003-04 rupees, except for the 10th Plan expenditure, which is given in current rupees since the national accounts are not available yet. Note that the outlay for the first plan is not given here, as the available data includes both power and multipurpose irrigation and power projects without disaggregation. Source: (Planning Commission, 2002a, 2005; CEA, 2007b).

It was with this philosophical backdrop that a new act – the Electricity (Supply) Act of 1948 – was passed to alter the existing institutional structure in the electricity sector and concentrate generation and bulk supply of electricity under the direction and control of one authority for healthy economic growth (GoI, 1948a). The Act allowed for the creation of a Central Electricity

[31] For example, the planned power sector outlay for the 9th Plan (1997-2002) was Rs. 124,526 cores (current). This amount is assumed to be given in 1996-97 prices, which is then converted to 2003-04 prices based on GDP deflators. Thus, the 9th Plan outlay in 2003-04 rupees is Rs. 171,106 cores.

Authority (CEA)[32] to develop "sound, adequate and uniform" national power policies, to coordinate and plan power development activities with existing licensees and the newly created State Electricity Boards (SEBs). The SEBs were to act as autonomous, corporate bodies under government supervision to establish power plants[33] and arrange for transmission, distribution and sale of electricity to consumers in the state (Datta, 1961). The SEBs were to create and administer regional 'grid systems', such that electricity generation would be concentrated in the most efficient units (GoI, 1948a). Generating Companies, owned by the State governments, the Central government, or both, were responsible for adding new capacity.[34] The role of the licensees (private companies) to generate and distribute electricity under the Indian Electricity Act of 1910 was taken over by the State Electricity Board in each state, under the CEA's guidance and national-level planning.[35]

Thus, electricity was deliberately placed in the public-sector domain and over the next two decades, public sector utilities, particularly the SEBs, began to dominate the power sector. While in 1950 the public sector owned only about 40% of installed capacity, by 1970 it owned about 80% of capacity – during this period, its capacity grew nearly twenty-fold (see Figure 5). By 1971, the SEBs generated about 66% of total electricity sold to consumers (Henderson, 1975).

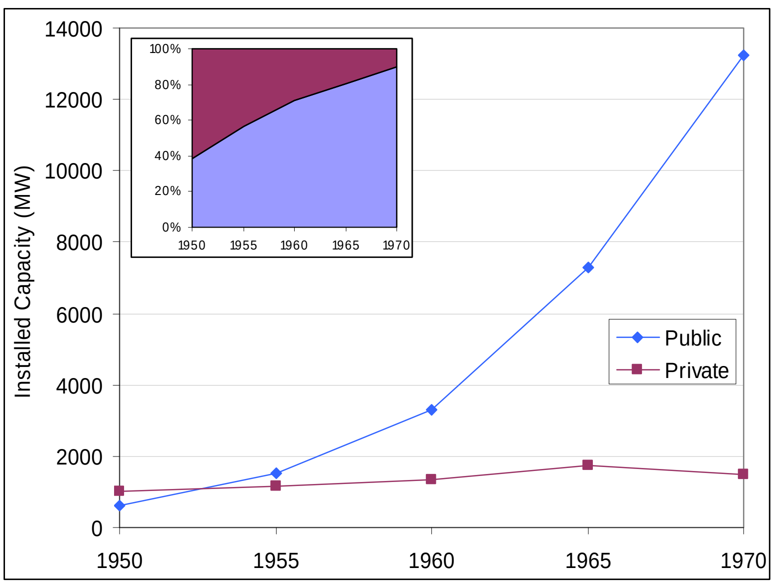

Figure 5: Rise of the Public Sector. Public sector (diamonds) and private sector (rectangles) installed capacity are shown from 1950 to 1970. The inset shows the same data in terms of percentage. Source: (Henderson, 1975).

[32] Although the CEA was established in 1950, it was only after the bifurcation of the Ministry of Irrigation and Power in 1975 that the CEA became fully functional, as per the 1948 statute, when the Power Wing of the Central Water and Power Commission was merged into it (Govil, 1998).
[33] The 1976 amendments to the 1948 Electricity (Supply) Act allowed for the creation of Central and/or State government owned electricity generating and transmission companies (Govil 1998 p. 256).
[34] If necessary, the SEBs could also take over private electricity generation companies; although, some of the existing private power utilities for some cities remained and they were allowed to augment their capacity as needed.
[35] The Constitution of India 1950 categorized electricity as a concurrent subject, i.e., under both central and state government purview.

Initially after independence, a key priority of the country was to become self-sufficient in food production, and hence the government planned to develop the irrigation and power sectors jointly.[36] There were also concerns about coal availability since explored coal resources in India were limited (60 billion tons (BT)) and 'workable' coal resource was estimated to be only 20 BT (Shah, 1949). The quality of Indian coal was also a concern – nearly 0.7 kg of coal was consumed to produce a unit of power,[37] unlike in Britain where the specific consumption was 0.4 kg/kWh (Shah, 1949). Hence, the initial emphasis was on producing power through large 'multi-purpose' hydroelectric projects that would provide both water and electricity for canal-based irrigation. The installed capacity of hydroelectricity in the country increased (an annual rate of capacity growth of 13% between 1950 and 1970); however, the generation from these projects was not as high as expected (annual rate of generation growth was 12% in the same period). The large river valley projects were complex and their construction took much longer than expected. In the meantime, electricity from coal continued its growth – coal-based generation grew annually at 13%, despite the fact that the annual rate of growth in installed capacity (1950-1970) was only 11%. Figure 2 and Figure 3 give graphical illustrations of the growth of the power sector from 1950 to 2004.

2.2.1 Introduction of pulverized coal technology

By the 1920s, a new technology for producing power using pulverized coal, allowing for greater efficiency and larger unit sizes, had been invented in the United States, and it was quickly deployed worldwide. In this technology, coal was no longer burned on stoker grates, but was pulverized into a fine powder[38] and introduced into the burners with pressurized air. The pulverization allowed for a hotter, more efficient, controlled burning of coal,[39] and the boilers using pulverized coal were larger, producing steam at higher pressures and temperatures. With increasing steam temperature and pressure, the efficiency of the steam turbine (and hence, of electricity generation) increased. As the steam-pressure and temperature increases to a critical point,[40] the characteristics of steam are altered such that water and steam are no longer distinguishable. If the temperature and pressure of steam is below this critical point, it is known as subcritical steam, and above this point, it is known as supercritical steam. The technology for generating electricity using subcritical steam parameters in a pulverized coal boiler is therefore termed *subcritical pulverized coal* technology.[41]

[36] In terms of government institutions, the Ministry of Irrigation and Power was created in 1952 and it continued its operations until 1975, when it was bifurcated into Ministry of Energy (along with Department of Power and Coal from the Ministry of Mines), and Irrigation was combined with the Ministry of Agriculture.

[37] Interestingly, the specific consumption of coal has not improved much at all over the next 50 years – in 2004, the specific consumption was 0.7 kg/kWh. The main reason for this is that despite improvement in efficiency of coal use in power plants over these years, coal quality has gotten correspondingly worse.

[38] Generally, about 70% of the coal is sized less than 75 μm (IEA, 2005a).

[39] For a more detailed description and technical details, refer to Merrick (1984), Ghosh (2005), IPCC (2005), and references therein; websites such as http://www.iea-coal.org.uk/site/ieaccc/home and http://europa.eu.int/comm/energy_transport/atlas/htmlu/heat_and_power.html.

[40] The critical point of steam-water, where water and steam are indistinguishable, is at a temperature of 374.15^{o}C and pressure of 218 atmospheres (221 bar or 225.6 kg/cm^2).

[41] The term "pulverized coal technology" includes all related technologies for coal preparation, boiler, turbine-generator, related accessories, and control systems.

Some of the earliest pulverized coal boilers for electricity generation in India – three 57.5 MW[42] units using Combustion Engineering (CE) boilers[43] and International General Electric (IGE) turbine-generators (TGs) – were installed in 1952-53 at Bokaro for the Damodar Valley Corporation.[44] The Bokaro plant was the first large plant in the country after independence, although there were several small plants (1 to 10 MW) being installed in many areas across the country at the same time (Subramanian, 1997). In 1960-61, the Indian Government bulk-purchased several 62.5 MW TG sets from IGE through an USAID program.[45] These TG sets were coupled with boilers from various manufacturers, including CE, B&W, Foster-Wheeler, AVB, and Poland (CBIP, 1997). Also in the 1960s, several imported 30 MW and 60 MW units were installed in several locations (CBIP, 1997; Subramanian, 1997; Govil, 1998). By late 1960s and early 1970s, larger units of 82.5, 100 and 140 MW were also bought from IGE. Similar to the bulk purchase from USAID, more than twenty 50 MW units were purchased in bulk from the former U.S.S.R., particularly for using lignite (Subramanian, 1997). Later, larger sized units (82.5, 100, and 150 MW) were also bought from the former U.S.S.R. As of 1997, at least 85% of Indian power plants had pulverized coal dry and/or wet bottom boilers (CBIP, 1997; Reddy and Venkataraman, 2002).[46] See Table 1 for a historical perspective on the growth of unit size and turbine efficiency of units in India.[47]

Growth of unit size and efficiency of installed units in India						
Unit Size	Period of Installation	Steam Parameters		Reheat	Design Parameters	
		Pressure	Temperature		Turbine Heat rate	Gross unit efficiency
(MW)		atm	^{o}C			
10	1935-1950	28-60	400-482	N/A	~2700	24-25%
30	1939-1974	66-70	482-488	N/A	2400-2470	28-30%
50	1962-1971	66-96	482-535	N/A	2280-2470	28-32%
57.5 - 67.5	1952-1990	88-98	510-535	N/A	2280-2350	31-32%
70 - 87.5	1960-1990	71-102	496-538	N/A	2350-2400	30-31%
100	1967-1974	90	535	N/A	2280	32%
110	1972-	130	535	535	2170	32.5%
120	1974-1988	126	538	538	2170	32.5%
140-150	1964-1972	125-168	538-565	538-540	1980	36-37%
200/210	1977 -	130;150;170	535-538	535-538	1980-2060	34-37%
500	1984 -	170	535-538	538-565	1940-1956	37-38%

Table 1: Growth of unit size and efficiency of installed units in India. Some of the recent units (130 MW, 250 MW, etc) are not included. This includes both foreign and indigenously manufactured units. The temperature ranges includes reheat.[1] Source: Adapted from Table 5.10 of Govil 1998.

[42] These units in Bokaro have now been derated to 45 MW (CEA, 2004b).
[43] Combustion Engineering (CE) in the United States was a pioneer in developing pulverized coal boilers for electricity generation (Kuehn, 1996). In the 1990s, Combustion Engineering (CE) was taken over by Asea Brown Boweri (ABB); ABB's subsequently merged its power generation business in a joint venture with Alstom, ABB Alstom Power. ABB eventually sold its share of the JV to Alstom.
[44] Damodar Valley Corporation is a joint public sector utility of the central government of India and the state governments of West Bengal and Bihar. It was incorporated in 1948, and modeled after the Tennessee Valley Authority in the United States. See: http://www.dvcindia.org/about/index.htm and http://www.dvcindia.org/power/sub/bokaroa.htm.
[45] Many associated auxiliaries for the TG sets were also bulk ordered at the same time (Subramanian, 1997).
[46] 14% of the power utilities did not report to the CBIP survey and 1% operated cyclone furnace and stoker boilers (Reddy and Venkataraman, 2002).
[47] See Subramanian 1997 and CBIP 1997 for more detailed historical information.

Many of these imported units suffered from many problems, primarily due to mismatch between designed and actual coal parameters. Many units were not able to each the rated maximum continuous power output. Some of the 62.5 MW GE manufactured turbines had problems with bolts and shaft stub shearing. The Russian turbines suffered from blade damage attributed to off-frequency operation. The poor quality of coal resulted in high erosion of boilers, burners, and heater piping. Hence, adapting these imported units to Indian conditions took a lot of time, and a heavy price was paid in terms of maintenance, repair, and modifications (Subramanian, 1997).

2.2.2 Indigenous manufacturing

Prior to independence, there were several small-scale power equipment manufacturers in India, which had technology collaborations with industries from the United States, Czechoslovakia, United Kingdom, France, and Germany (Govil, 1998). However, the post-independence industrial policies precluded the private sector from manufacturing utility-scale power plant equipment. The 1948 Industrial Policy Resolution called for 'prime-mover', 'electrical engineering', and 'heavy machinery' industries to become subject of Central government regulation and control in the national interest. The 1956 Industrial Policy Resolution went even further by stating that the heavy electrical machinery and generation and distribution of electricity were to be the exclusive responsibility of the State (GoI, 1948b, 1956). However, despite these Resolutions, the government effectively welcomed foreign capital and technology, primarily because of limitations in resources to meet industrial objectives, depletion in foreign reserves, and influence by the World Bank and USAID (Dhar, 1988). By 1958, heavy electrical machinery was opened up to the private sector, in spite of this industry being specifically allocated for the public sector (Dhar, 1988).

In 1959, the Associate Cement Company (now known as ACC) joined with two U.K. companies—Vickers and Babcock & Wilcox—to form a new company called the ACC-Vickers-Babcock (AVB) limited.[48] AVB started the manufacturing of small boilers and it primarily supplied technical support and equipment to power plants (and other industries) in West Bengal.[49] By 1967-68, some of the first indigenously manufactured boilers from AVB were coupled with the USAID-supported 62.5 MW IGE turbines in Delhi and Satpura. Other foreign private companies that entered India around the same time include the English Electric Company and Siemens.

However, comprehensive manufacturing capacity for power plants in India only became a reality with the setting up of public sector manufacturing units in the 1960s.[50] They produced

[48] By the mid 1980s, AVB became unprofitable, and it was shutdown in 1986. In 1989, the central government took over operations, and the company was renamed as ACC Babcock Limited (ABL). Later, ABL was taken over by Alstom and it was known as Alstom Power Boilers. Recently, this new company has become part of Alstom Power. See: "Alstom plans expansion of plant in Durgapur", The Statesman, Nov 1, 2006.

[49] See: "Alstom plans expansion of plant in Durgapur", The Statesman, Nov 1, 2006.

[50] Key plants included (Govil, 1998):

- Heavy Electricals Limited (HEL) in Bhopal (1960) to manufacture steam and hydro turbo-generators, motors, transformers and capacitors;
- Heavy Power Equipment Plant (HPEP) in Hyderabad (1965) to manufacture steam turbo generators up to 110 MW, boiler feed pumps, condensate pumps, etc.;
- High Pressure Boiler Plant (HPBP) in Tiruchirapalli (1965) to manufacture main steam boilers (60-210 MW), Air pre-heaters, precipitators, etc.;

indigenously manufactured steam and hydro turbo-generators, steam boilers, feed pumps, condensate pumps, coal mills, precipitators, and other electrical equipment necessary for constructing power plants in India. A holding company, Bharat Electricals Limited (BEL) was incorporated in 1964 to manage and coordinate activities of some of these companies (HPEP, HPBP and HEEP – see footnote 50).

These new public-sector manufacturing industries also had significant technology collaborations with European, U.S., and U.S.S.R. companies, in order to accelerate the pace of manufacturing and to meet the constraints imposed by financial institutions for providing capital for these industries (Lall, 1987; Govil, 1998).[51] The only difference in comparison with the pre-independence situation was that the technologies were now imported into large public sector companies, rather than small private firms. Thus, BEL's indigenous equipment was dependent on foreign technology designs – licensed from private foreign companies, such as SKODA of Czechoslovakia, CE of United States, Promash of Russia, KWU (Siemens) of Germany, and others. Interestingly, many of foreign companies that had collaborations with BEL[50] to provide technology for manufacturing power plant equipment in India also independently installed power plants in India. Therefore, a number of fully imported power plants from various countries including the United States, U.S.S.R., Czechoslovakia, United Kingdom, Poland, Germany, and Japan were set up during this period. The multiplicity of collaborators led to situation where there were many different unit sizes within a close range, but with different design features and parameters (Subramanian, 1997).

- Heavy Electrical Equipment Plant (HPEP) in Haridwar (1967) to manufacture steam turbo-generators (100-200 MW), large motors, hydro TG sets, etc.;
- Instrumentation Limited (IL) in Kota (1968) to manufacture control equipment, instrumentation and control systems for power plants.

[51] In fact, some of these plants were provided on a turnkey basis, and they were all designed and executed by a varied group of foreign collaborators (Lall, 1987).

2.3 Public-sector dominance and crisis (1970-1990)

The successful rise and strong growth of a publicly-owned power sector in India in the first two decades after independence cemented its domination. While the state sector was the principal in these early decades, the central sector soon began to play an important role. New centrally owned public sector corporations were established to increase capacity[52] – National Thermal Power Corporation (NTPC) in 1975, National Hydro Power Corporation (NHPC) in 1975, and Nuclear Power Corporation of India Limited (NPCIL) in 1987. These new central companies were aimed at supplementing the generation activities of SEBs and the existing public sector companies. In terms of percentage of overall installed capacity, the central sector grew from 17% to 32% from 1970 to 2003, and for coal-based capacity from 22% to 36% in the same time period (see Figure 6). The private sector continued to be marginalized— in 2003, it only had about 6.5% of coal-based capacity and about 11% of overall capacity.

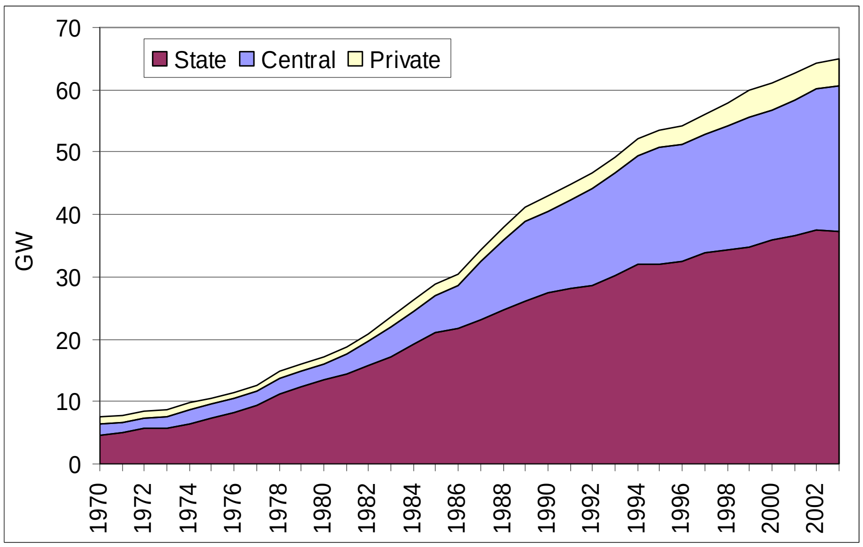

Figure 6: Ownership of installed capacity of coal-based power plants (1970-2003). The state category also includes plants owned by local municipal bodies. The central category also includes DVC-owned plants. Source: (CMIE, 2005).

The rapid growth of the publicly-owned power sector, however, masked a number of problems. The energy scene of the early 1970s was marked by power shortages and frequent power plant breakdowns. Hydroelectric plants were suffering from low generation, as water resources depended heavily on erratic monsoons. In the early 1970s, growth in generation from hydroelectricity reduced significantly because of poor monsoons (see Figure 3), with only a 4% increase during the Fourth Plan (1969-1974). Other reasons, in addition to monsoons, included long construction times, delays in civil works, delays in delivery of power plant equipment, higher-than-expected capital costs, and inadequate addition of transmission and distribution infrastructure (Henderson, 1975; Ramanna, 1980). Growth of hydroelectricity was further

[52] Many critics suggest that the World Bank played a crucial role in the creation of NTPC and NHPC in order to protect its investments in the Indian power sector, since corporations backed by the central government would provide lower credit risks and greater borrowings than the SEBs (Govil, 1998; Rao, 2002).

stalled due to resistance from local groups against the construction of large hydro-electric dams, as they led to large-scale displacement and submergence of forests. Hence, in the 1970s and 1980s, the growth in hydro-electric installed capacity was only 6% and 5%, respectively, half as slow as in the previous two decades. Despite this increase in capacity, generation of hydropower has been very poor. From the late 70s to the late 80s, there was almost no growth at all in generation (see Figure 3), and hydroelectric generation fell from being nearly 40-45% of total generation to about 20-25%. This drop in the contribution of hydroelectricity to total generation is still continuing—in 2004, hydroelectricity only contributed about 14% of total generation (see Figure 7).

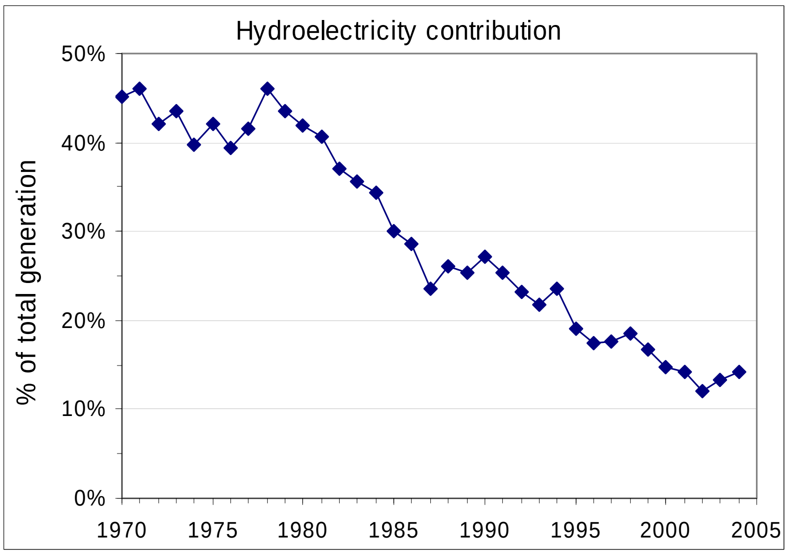

Figure 7: Hydroelectricity contribution to total generation (1970 - 2004). Source: Same as Figure 2

Generation of electricity from nuclear sources had just begun with the commissioning of the Tarapur Atomic Power Station near Bombay. However, this nascent development was superseded by the international sanctions imposed on India because of its 1974 nuclear weapons test (Gopalakrishnan, 2002). The international embargo slowed the rate of technology development and installation of new nuclear plants in India, as indigenous capacity had to be built up.

Furthermore, the oil-shocks of 1973 and 1978 marginalized the use of oil for power generation. Although the shocks did not directly affect the Indian energy sector, it had significant ramifications for India's balance of payments and external financing, resulting from high import bills for petroleum (Henderson, 1975). Unlike some of the OECD countries, much of the Indian energy crisis in the 1970s was due to internal problems related to failure of hydroelectricity and coal shortages. Moreover, as Pande (1980) and Reddy and Prasad (1980) point out, the energy crisis caused by the oil shocks affected only the lifestyles of the affluent strata,[53] whereas the other 60% of Indian population lived in a "permanent energy crisis". Nonetheless, the oil crisis made the use of indigenous coal and hydroelectricity relatively cheaper and forced the

[53] 20 to 40% of Indian population consumed almost all commercial energy in India (Pande, 1980).

government to emphasize coal usage in many energy-intensive sectors including electricity generation (Chakravarty, 1974; Pande, 1980).

Thus, the power sector became highly dependent on coal – as indicated by the enormous increase in coal power capacity and generation throughout the 1970s and 80s. The installed capacity of coal power grew by 8% annually in the 1970s and 10% annually in the 80s – Figure 8 and Figure 9 show the unit sizes of currently operating power plants as a function of the year when they were commissioned. Note that more than 200 new coal power plant units (mainly 110 and 210 MW sizes) were installed in between 1970 and 1990, in contrast to only about 75 units (consisting mostly units less than 100 MW) in the previous two decades (see Table 2 and Figure 9). The total coal based capacity in 1990-91 was 43 GW, compared to 7.5 GW in 1970.

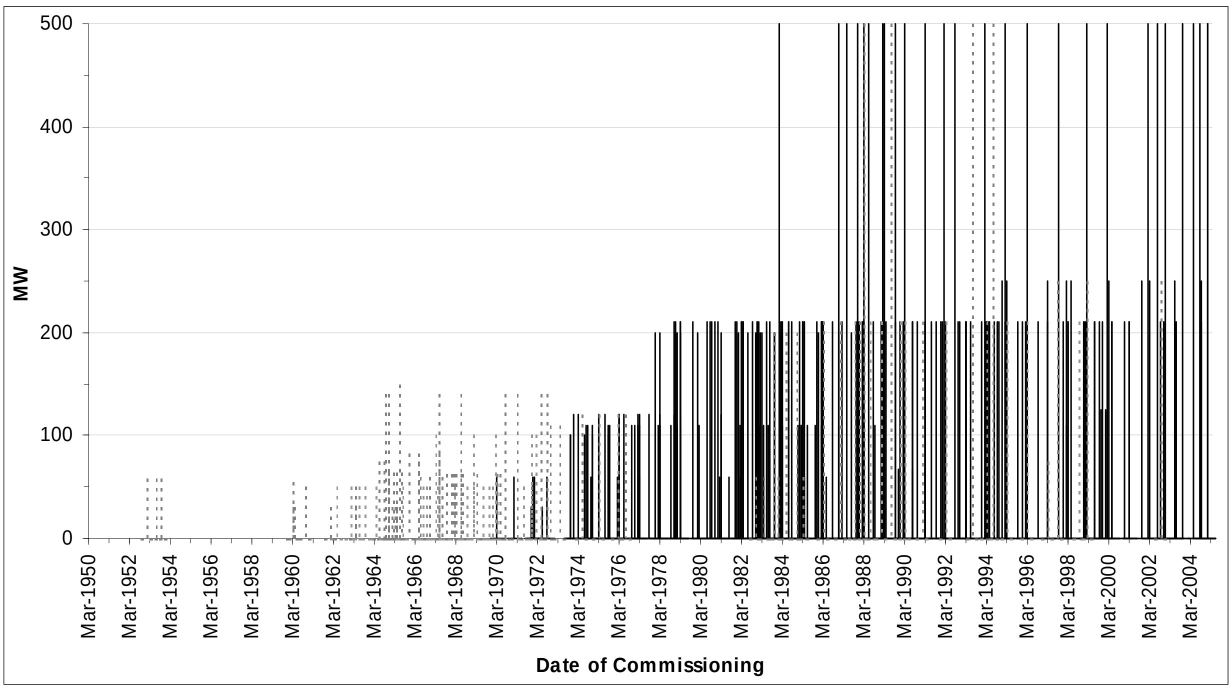

Figure 8: Installation dates of currently operating coal and lignite based power plants in India. Each line represents the capacity of the installed units as a function of their year of commissioning (1950 to 2004-05). The dashed lines indicate foreign units and solid lines indicate BHEL units (including those with AVB boilers and BHEL turbines). The density of lines gives an indication of the rate of commissioning new plants, and it is greatest in the 1980s and early 1990s. All of the units (< 30 MW) installed prior to 1950 (expect for New Cossipore, which were installed in 1949) are no longer in operation, and most of the units installed in the 50s have been decommissioned. Source: CEA – General Review and Performance Review of Thermal Power Stations (various years), and websites of various utilities, CEA and the Ministry of Power. Most of the installation dates is taken from (CEA, 2006b).

a)

Age (as of March 31 2005)	Number of Units					Installation year
Unit Size (MW)	**<100**	**100/110/120/ 140/150**	**200/210/ 250**	**500**	**Total**	
< 5 yrs		1	14	8	**23**	2001 >
5 - 10 yrs	1	6	24	4	**35**	1996-2000
10 - 14 yrs	3	1	38	7	**49**	1991-1995
15 - 19 yrs	5	8	40	11	**64**	1986-1990
20 - 24 yrs	9	15	40	1	**65**	1981-1985
25 - 29 yrs	2	23	16		**41**	1976-1980
30 - 34 yrs	9	24			**33**	1971-1975
35 - 39 yrs	38	6			**44**	1966-1970
40 + years	29	3			**32**	< 1965
Total	**96**	**87**	**172**	**31**	**386**	

b)

Age (as of March 31 2005)	Installed Capacity					Installation year
Unit Size (MW)	**<100**	**100/110/120/ 140/150**	**200/210/ 250**	**500**	**Total**	
< 5 yrs		120	3165	4000	**7285**	2001 >
5 - 10 yrs	75	740	5280	2000	**8095**	1996-2000
10 - 14 yrs	205	120	8060	3500	**11885**	1991-1995
15 - 19 yrs	332	890	8370	5500	**15092**	1986-1990
20 - 24 yrs	540	1670	8270	500	**10980**	1981-1985
25 - 29 yrs	120	2640	3290		**6050**	1976-1980
30 - 34 yrs	460	2710			**3170**	1971-1975
35 - 39 yrs	2210	720			**2930**	1966-1970
40 + years	1466	430			**1896**	< 1965
Total	**5408**	**10040**	**36435**	**15500**	**67383**	

Table 2: Size and vintage of coal-based units in India. The number of units within particular unit sizes is shown in (a) as a function of installation year; (b) shows the installed capacity. *Source: same as Figure 8.*

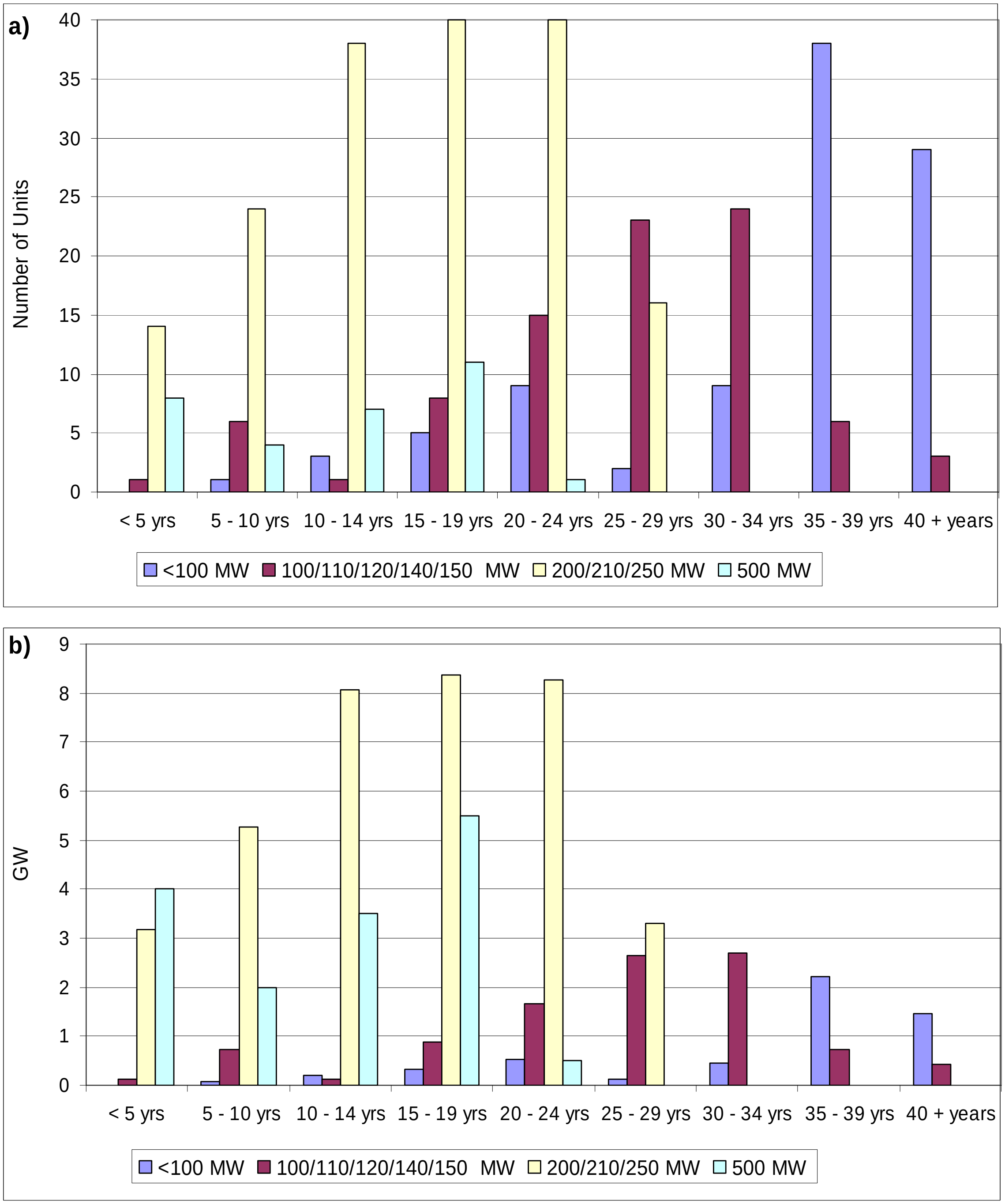

Figure 9: Size and Vintage of operating Indian power plant units (up to March 31, 2005) – A graphical illustration. *Source: Same as Figure 8.*

The emphasis on coal-based power generation was also evident at the ministerial level. In 1975, the government created a Ministry of Energy by merging two existing departments: the Power Wing of the Ministry of Irrigation and Power and the Department of Power and Coal from the

Ministry of Mines.[54] The link between irrigation and power was officially broken. To further consolidate the generation of electricity using coal and to ensure adequate supply to the various power plants and industries, the government nationalized the coal mines in 1971-73. With the government ownership of coal mines, the production of coal increased. Coal India Limited (CIL) was created in 1975 as a holding company for the entire coal industry in India that included various state-owned mining companies and research institutes (Krishna, 1980).[55] The Ministry of Energy, along with the Planning Commission, CEA, CIL and others, coordinated the overall planning for coal mining and electricity production in India. One of key roles of the CEA in this process was to provide technical guidance, approve cost estimates and give techno-economic clearances (TECs) for power plants in order to ensure that they are technically and economically viable.[56,57]

Also in this period, the environmental impacts of thermal power generation were becoming more apparent, and the government engaged in efforts to mitigate such impacts. The key issue in particular was reducing particulate emissions. Given the high ash content of Indian coals, particulate emissions in stack flue gases were particularly high. Hence, power plants were required to use better pollution control equipment to limit emissions.[58]

There was also greater emphasis on producing thermal power at pithead locations. Since coal is India is concentrated in the eastern and southeastern regions of India, it was more economical to locate power plants at the pit head of coal mines rather than transporting the coal to power plants near load centers. For example, one of the primary goals of NTPC was to accelerate the installation of pithead coal power plants, and provide additional thermal power capacity to the regional grids.

2.3.1 Dominance of BHEL power plants

BEL and HEL plants had little coordination between them with significant errors in planning and implementation of their plants. Poor management combined with incompatible designs and manufacturing processes in these plants led to considerable losses (Lall, 1987). Nevertheless, these plants began to supply equipment by 1965 and their first 30 MW TG unit was commissioned in 1969 at the Ennore power plant in Tamil Nadu. The first indigenously manufactured boiler and turbine-generator (TG) unit was installed by 1970, also at Ennore – this was a 60 MW unit using pulverized coal boiler technology with design steam parameters of 90 atmospheres and 535^{o}C, and design turbine efficiency of about 30% (Govil, 1998).[59]

---

[54] The Ministry of Energy was again broken up in 1992, with the Ministry of Power being one of the resulting ministries.
[55] Initially, Coal India Limited had 5 subsidiaries: Bharat Coking Coal Limited (BCCL), Central Coalfields Limited (CCL), Western Coalfields Limited (WCL), Eastern Coalfields Limited (ECL) and Central Mine Planning and Design Institute Limited (CMPDIL).
[56] Ministry of Power website.
[57] Power plants were also required to obtain forest clearances from the Ministry of Environment and Forests after the 1980 Forest Conservation Act.
[58] Legally, the state pollution control boards have to give pollution clearance for plants prior to its construction.
[59] Currently, this Ennore unit is operating with a gross efficiency of 24% and a net efficiency of only 20%. The PLF is also quite low at around 50% (CEA, 2005f).

In 1973, a major reorganization of power plant manufacturing industries led to the formation of a new holding company, Bharat Heavy Electrical Limited (BHEL), to take over the management of BEL and HEL, with a dynamic new chairman and improved top management (Lall, 1987). BHEL coordinated the manufacturing of power plant equipment, added new manufacturing plants, and infused new licensed technologies in the older plants. BHEL also started a formal corporate R&D at this time. Soon after, BHEL rapidly began to manufacture larger-sized units. The first indigenous non-reheat 100 MW unit was installed at Badarpur in 1973, the first 110 MW reheat unit at Kothagundem in 1974, the first 200 MW unit at Obra in 1977[60], and the first 500 MW at Trombay in 1984.

In the following decades, BHEL completely dominated the power plant supply – during 1970-80, more than 60% of the units were manufactured by BHEL and during 1981-91 almost all of the power plants were of BHEL-make (see Figure 8). The recommendations of an advisory sub-group on technology development in 1986 ruled out the use of supercritical steam parameters in India and noted that the Indian power sector should rely on 500 MW units until 2000, with a review of technology status in 1990-91 (CEA, 2003). As a result, all of the power plants in India continued to be based on subcritical steam generation.

2.3.2 Limited indigenous technological capability

While there was a great emphasis on increasing coal-power capacity and generation, the power plants were suffering from a serious underutilization of capacity (PLF ranged in the 40-50%) and being out of commission for longer periods than necessary for routine maintenance (Henderson, 1975). In many cases, lack of regular coal supply and poor quality of coal limited the generation.[61] Ironically, one of the key problems in coal supply was interruptions in power supply to coal mines,[62] particularly in the Bengal and Bihar areas (Henderson, 1975) – leading to a vicious circle wherein the lack of coal and power limited each other's growth. The poor quality of coal increased the wear and tear of auxiliaries, such as coal mills, pulverizers, burners, draft fans, coal pipes, piping at the super heater and economizers, and on heater seals and tubes (Subramanian, 1997). Furthermore, coal-handling equipment was affected by inconsistent and higher coal size than design, which affected plant operations and reduced plant load factors.

The BHEL manufactured equipment also suffered from many manufacturing and teething problems. In spite of importing 'best available' modern technologies, the BHEL manufacturing capabilities were found wanting. The 200/210 MW power plants, in particular, had significant operational problems – by 1982-83, these 200/210 MW power plants were operating with availabilities as low as 60% (PLF as low as 40%), with routine outages (Govil, 1998; Ministry of Power, 2005). According to the Ministry of Power,[63] some of the reasons for these teething problems included:

- design deficiencies, manufacturing, and generic defects,

[60] The 200 MW unit at the Obra plant in Uttar Pradesh was of Russian (LMZ) design. The first 210 MW unit of Siemens (KWU) design was commissioned at Korba west plant in Maharashtra in 1983. The KWU-design-based units were more efficient than the LMZ-design-based units (CEA, 2003).
[61] Even by early 70s, it was realized that high ash content and abrasive material in coal were causing serious damage to coal preparation equipment and boilers (Henderson, 1975).
[62] In addition to lack of power, lack of adequate transportation for coal (limited by various factors) and shortage of spares also limited coal production (Henderson, 1975).
[63] http://powermin.nic.in/generation/renovation_modernization_thermal.htm.

- lack of proper operation and maintenance (O&M), causing prolonged and repetitive forced outages,
- inadequate and non-timely availability of spare parts especially for imported equipment,
- lack of resources with SEBs even for making payments to BHEL against supplies & services and for coal supplies to coal companies,
- quality of coal was much lower than design values; coal had high ash content and contained stones, boulders, shale and sand, and
- excessive and inadequately trained manpower for the O&M of the plants.

The first BHEL power plants had small margins for fuel quality variability and designed for high calorific values of domestic coal that were no longer available (Govil, 1998). Thus, the gradually degrading coal quality made operation of these BHEL power plants highly inefficient with constant breakdowns. Foreign collaborators, who could not directly invest in India because of government restrictions, had little motivation to solve the actual operational problems on the ground.[64] In essence, BHEL seemed to focus more (at least initially) on replication of borrowed technology and less on adaptation of these technologies to the Indian context. Some of these problems could be attributed to initial learning problems, as suggested by Subramanian (1988), but it could also be that BHEL did not put enough effort in technology adaptation and training of engineers and plant operators. Although there were efforts on indigenizing and standardizing products, greater emphasis on increasing technological capacity – particularly the 'know-why' aspects – would have been helpful.

The problems with the 200/210 MW were finally solved by Indian engineers. In 1984-85, 'roving' teams of engineers from CEA, BHEL, Instrumentation Limited (Kota), and utilities (NTPC in particular) took to visiting various power plants.[63] They analyzed the problems at each power plant, studied the design deficiencies, and worked with BHEL and other manufacturers to modify the existing equipment. With this effort, the efficiency and PLF of the 200/210 MW units improved. Much of this learning and modifications was used to implement the necessary changes into the design and manufacturing processes of future 200/210 MW units. In addition, the Ministry of Power began to provide financial support to SEBs to rehabilitate their power plants through its Renovation and Modernization program.[63] This program was crucial in helping to improve the efficiency of Indian power plants.

On hindsight, the teething problems associated with the 200/210 MW units were not unexpected. Even before BHEL was officially incorporated, the Power Economy Committee in 1970 reported that the indigenous manufacturing units had difficulties adapting foreign power technology to Indian conditions, and that design capabilities had to be developed in manufacturing units (Govil, 1998). A 1974 report by the National Committee on Science and Technology (NCST) noted that improving the availability and utilization of existing units requires the development of indigenously manufactured spares for critical parts, the need for including reserve capacity in critical equipment (such as pulverizers, feed water pumps, etc.), standardization of power plant designs, and increase in R&D (NCST, 1974).

[64] Based on interviews with NTPC and BHEL officials (February 2005). Since personal interviews were conducted on a 'not for attribution' basis to increase candor and honest assessments, names of officials interviewed are not given here.

This pattern of importing technologies for coal-based power generation continued. Whenever new technologies or designs for larger-sized power plants were needed, they were wholly imported through comprehensive foreign collaborations and licensed into the BHEL repertoire (see Table 7.7 of Govil (1998) for an exhaustive list of BHEL's foreign collaborations from 1961-1988). Thus, technology improvements seem to come only through new foreign collaborations rather than indigenous technology development. Apparently, this preference for importing/licensing new technologies is endemic in the power sector. For example, in the early 1980s, BHEL management and government officials opted for collaborating with KWU (Siemens) of West Germany for 500 MW TG sets, despite having spent significant resources to build in-house knowledge and capacity for designing and developing this equipment.[65] In fact, the indigenous development of the 500 MW unit was considered as a National Product Development Project and was accorded high priority by the science and technology establishment. It was expected that existing technology capacity, combined with a moderate amount of foreign assistance in areas where know-how was lacking, would be enough to develop the unit (NCST, 1974).[66]

More recently, BHEL lost a bid to install supercritical boilers at Sipat in 2004 because the NTPC project tender required BHEL to collaborate with Alstom to provide guarantees and 'experience', thereby making the bid too expensive (Airy, 2003; Ramesh, 2005).[67] BHEL also lost a bid to install a 250 MW power plant using circulating fluidized bed combustion (CFBC) boilers in Neyveli in 2005, because BHEL was forced to collaborate with Lurgi to meet the tender requirements (Ramesh, 2005). Thus, BHEL has repeatedly relied on foreign collaborations for manufacturing larger and more advanced technologies.[68]

Interestingly, Govil (1998) also notes that after NTPC's formation, the number of foreign collaborations increased, most likely due to the increased reliance on foreign consultants for technical assistance. These foreign consultants, who naturally were more familiar with their own equipment manufacturers, might have promoted foreign technology rather than indigenously developed technology.

2.3.3 Financial problems in SEBs

While BHEL's manufacturing problems were resolved through increased attention to engineering and plant operations, there were deeper problems within power sector. The optimism and exuberance of the post-independence period for government ownership, with the intention of social good and equity, morphed into pessimism about the government's ability to provide reliable power. A major part of the problem was the political interference that began to destroy the financial viability of the SEBs, which in turn became a key driver for the power sector reforms in the 1990s.

[65] BHEL invested Rs. 52 cores (as well as significant human resources) to design and prepare for the manufacture of the prototype 500 MW boiler, turbine and auxiliaries (Govil, 1998).
[66] The NCST (1974) estimated that 8 cores would be needed for R&D and 72 cores for prototype development.
[67] The bid for the Sipat 3x660 MW supercritical power plant was won by Doosan Engineering of Korea (Ramesh, 2005).
[68] In addition, BHEL's decision to provide turnkey execution of projects led to reduced discussions with utilities – thereby limiting development of knowledge and expertise within utilities.

When initially established, the SEBs were planned as autonomous commercial entities. However, the SEBs were forced by the State governments into having contradictory goals of meeting "social objectives" (namely, rural electrification and energizing of agricultural pump-sets) and commercial considerations.[69] The SEBs were also not free to distribute power on a commercial basis, as they were highly susceptible to political influences. Politicians, who were keen to exploit the rural voting blocs, gave farmers practically free electricity for irrigating their lands by electrifying their tube wells for groundwater pumping and by installing pumps for extracting water from canals.[70] Thus, in the name of removing poverty and improving food security, flat-rate tariffs based on electricity connections rather than on metered consumption soon became the norm in rural areas of many states.

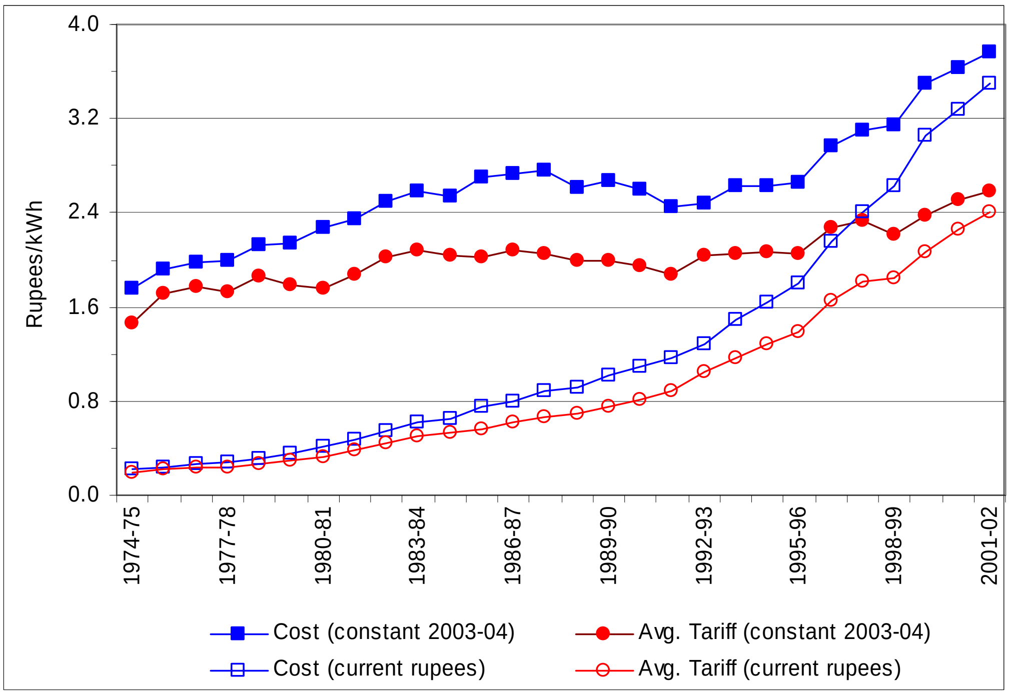

Figure 10: Cost of Supply and Average Tariff. The solid markers show cost of supply (generation + transmission and distribution) and tariff in real rupees (2003-04 rupees), and the open markers show cost and tariff in current rupees. The current costs were converted to constant rupees using GDP deflators using data from the Central Statistical Organization. Source: (Planning Commission, 2002a); revised estimates used for 2000-2001; estimates from the Annual Plan used for 2001-02.

With these entitlements, the share of agriculture in the consumption of electricity increased from 9.2% in 1970-71 to 23.9% by 1990-91 (Tongia, 2003). Even domestic customers in most states had tariffs that were much lower than actual cost of supply. In order to make up for these losses, the SEBs set higher tariffs for industry, railways, and commercial establishments, which resulted in cross-sectoral subsidies.[71] The high tariffs for electricity, combined with poor quality of

[69] Rural electrification, which was not commercial in the pre-independence period, continued to be unremunerative.
[70] Popularization of the 'Green Revolution' led to greater water, fertilizer and pesticide inputs into agriculture; irrigation pump sets allowed for delivery of large amounts of water needed for such input-intensive agriculture.
[71] This situation was entirely different from the early 1970s. In 1971-72, the average revenue from domestic and commercial (Rs. 0.31/kWh) consumers was nearly 3 times more than from industrial consumers (Rs. 0.11/kWh), and almost two times more than agricultural consumers (Rs. 0.16/kWh) (Henderson, 1975).

supply, forced many of the industries to ‘opt-out’ of the grid and generate ‘captive power’ on their premises. The share of the industrial consumption in the overall consumption of electricity dropped from 62.6% in 1970-71 to 50.8% in 1990-91 and further to 30.5% by 2000-01 (Tongia, 2003), making the SEBs’ financial situation even more dire. Thus, the SEBs were being run into the ground financially because of the large disparity between the cost of electricity supply to their customers and the tariffs paid by the customers (see Figure 10).

While tariffs were altered and cash inflow for supplied electricity decreased, SEBs were squeezed on the other end by their legal obligations and by the central utilities’ demand for payment. As per the Electricity Supply Act 1948 statute, SEBs were obligated to operate with a 3% minimum rate of return on net asset value.[72] However, this was an impossible task as the accruals into the SEBs did not meet their expenditure; hence, the accounting system was manipulated to meet this requirement (Tongia, 2003). With the creation of the central public sector utilities (CPSUs), the interests of the central government and the state government have been in conflict. NTPC and NHPC were obligated to pay back their creditors (World Bank and others) regularly in order to ensure that they continued to receive financing for more capacity additions. Hence, the central government set high tariff rates for the bulk electricity purchased from the CPSUs by the SEBs; these tariffs have also been increasing more than the rate of inflation on many other services (Rao, 2002). Thus, the SEBs have had to rely on state government subventions, cross-subsidies and other accounting manipulations (Tongia, 2003) in order to ensure that they meet their legal obligations.

Finally, the poor financial situation of SEBs was exacerbated by policies of external financiers. The importance of the World Bank and other multilateral lending agencies in influencing Indian government and its power policies cannot be underestimated (Rao, 2002). The World Bank, which provided financing for many of the Indian power plants, did not address the SEB management issue directly, but instead it actively supported NTPC, which was to supposed to be a model for the SEBs to emulate (Dubash and Rajan, 2001).

All of these factors – political interference in tariff setting, the central government’s interest and the World Bank’s emphasis on the CPSUs – contributed to financial problems and an ensuing lack of professional management in SEBs. This in turn led to issues such as poor quality of electricity supply to the grid, high technical losses during transmission and distribution, increase in theft of electricity, and poor metering, which further worsened the financial problems of the power sector.

[72] A chairman of SEB contended that since tariffs were exogenously determined and the choice of priority sectors for supply lies with State governments, the rate of return yardstick is inapplicable to SEBs (Dayal, 1980).

2.4 Liberalization and restructuring (1991-2003)

By the late 1980s, the Indian economy was in the doldrums; rising external debt along with large fiscal deficits (close to 9% of GDP) led to a macroeconomic financial crisis in 1990-91. In order to prevent default, the Indian government had to accept a major structural adjustment program, including large devaluation and deflationary fiscal measures, deemed necessary by official donors and lenders. The resulting macroeconomic stabilization and structural adjustment included substantial changes in fiscal and trade policies, as well as reforms in the industrial and financial sectors (Joshi and Little, 1996). Private companies were now allowed to build, own, and provide infrastructure services in India, and the power sector was at the forefront of this change (Dubash and Rajan, 2001).

2.4.1 IPP fiasco

The 1991 crisis was a perfect time to rescue the power sector away from politicians, to reassert the independence of the SEBs, to reframe the tariffs rationally, and to devise mechanisms of accountability (Dubash and Rajan, 2001). Yet, the government, embracing the ideology of the time[73] rather than critically and independently assessing the country's goals and requirements, was solely focused on attracting foreign capital and equity to build up power generation. Instead of dealing with the fundamental problems of the SEBs, the central government decided to 'liberalize' the power sector and entice foreign private companies to bring their finances and technology into the Indian power sector. In 1991, the government amended the Electricity (Supply) Act 1948 to allow private companies own power plants and generate electricity as Independent Power Producers (IPPs).

The IPPs were given lucrative incentives,[74] and by mid-1995, about 189 projects with a total capacity of 75 GW were proposed, with 95 projects (48 GW) having Memorandums of Understanding and Letters of Intent (Dubash and Rajan, 2001). But, eventually, most of these projects either became stalled in the approval process[75] or did not reach financial closure. In addition, many of these projects were based on expensive liquefied natural gas (LNG), natural gas (NG) or naphtha, rather using the inexpensive, albeit poor quality, Indian coal.[76] In order to expedite these projects, the central government 'fast-tracked' eight projects with offers of counter-guarantees—only three have produced electricity thus far (Tongia, 2003).

[73] The ideology of privatization and liberalization in the electricity sector was not unique to India, but it was systematically pushed by the World Bank and other multilateral financial agencies to increase the role of private (foreign) capital in developing countries through its Structural Adjustment Programs (SAPs). See for example, Dubash (2002).

[74] Key incentives for the IPPs included a *guaranteed* minimum of 16% rate of return (after-tax) on equity, full repatriation of profits in dollars, five-year tax holiday, guaranteed off-take and payment, high cost-plus tariffs, and selective counter-guarantees from the central government in case of payment default by the SEBs (Dubash and Rajan, 2001; Tongia, 2003).

[75] The IPPs still had to go through the CEA's techno-economic clearance process if they were large enough. Some have suggested that many IPPs decided to go for smaller, albeit uneconomic, projects in order to avoid the CEA clearance process (Ranganathan, 2004).

[76] By 1999, about 2,746 MW of imported oil/gas-based IPP plants were commissioned and 3,343 MW plants were under construction, in comparison only 411 MW IPP plants based on coal were commissioned and another 500 MW were under construction (Phadke, 2001).

In essence, the IPP liberalization policy of 1991 was a dramatic failure. Despite the initial hype of increasing generation in the private sector, during the second half of 1990s, twice as much capacity was added in the public sector as in the private sector (Tongia, 2003); by 2003, only 5.3 GW of IPP projects[77] were fully commissioned (TERI, 2004). The overall capacity addition in the country slowed down in the mid-to-late 1990s, as indicated in Figure 2 and Figure 9. Operating IPPs further eroded the SEB finances because of the high price of electricity that resulted from the incentives given to IPPs. All things wrong with the 1991 IPP liberalization policy were symbolized by the Dabhol power plant, which was promoted by the now-defunct Enron Corporation. Many books and articles have described the sordid details of the Dabhol/Enron scandal[78], and hence it is not discussed here in detail. Suffice it to say that the power plant is still mothballed, and efforts to restart the plant under NTPC management are underway. Attempts to bypass the approval process and the resultant violation of environmental norms by some of the IPP projects resulted in agitations against them and forced their eventual closure.[79] By end of the 1990s, most of major actors in the power sector began to disavow the IPP policy, but by that time, the sector had already entered the restructuring and privatization phase.

2.4.2 Continued failure of SEBs

While the central government was dealing with the consequences of its failed IPP policy, the financial condition of the SEBs went from bad to worse. As discussed earlier, the SEBs were in dire financial straits mainly because their inability to make up for the increasing cost of electricity supply by appropriate tariffs and collection of dues (see Figure 10). Cost recovery based on tariffs was below 70% in 2001-02 and getting worse. In addition, inefficient collection practices prevalent at local distribution networks had further pushed the SEBs into financial insolvency. The increasing commercial losses (Figure 11) and high negative rate of return (Figure 12) highlight the deplorable status of the SEBs. Over the past decade, much of the SEB losses have been partially hidden by subventions paid to the SEBs by state governments. On average, these subventions have covered about 50% of the total loss, although the range of government subvention has ranged between 30-90% (see Figure 11).

[77] This includes the controversial and currently shut-down 740 MW Dabhol/Enron gas-based power plant in Maharashtra.
[78] See for example: (Mehta, 2000; Dubash and Rajan, 2001; Parikh, 2001; Prayas, 2001, 2005).
[79] For example, the 1000 MW coal-based Cogentrix project was closed down in 1999 after being taken to the courts and opposed by local groups on social, economic and environmental grounds (Fernandes and Saldanha, 2000).

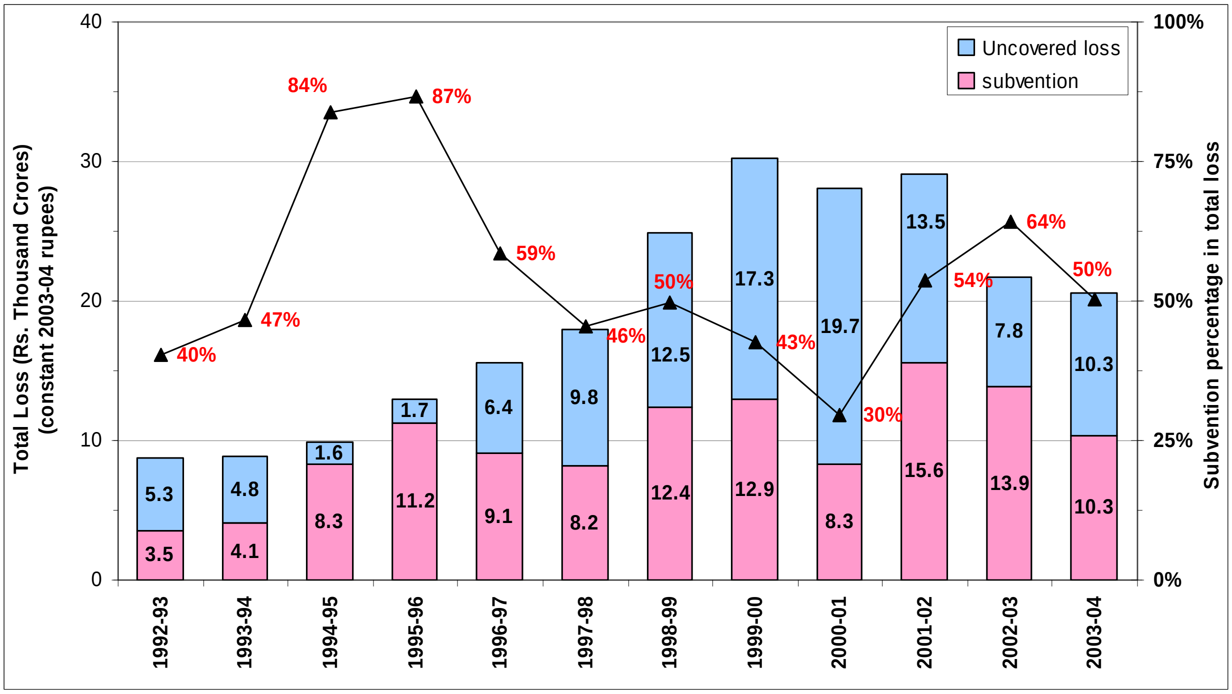

Figure 11: Loss of SEBs. The annual total loss of the SEBs is shown in constant 2003-04 rupees. The losses are made up partially by State government subventions (indicated above). The fraction of State subvention relative to the total loss is also shown (right axis). Source: 1992-2001 – (Planning Commission, 2001, 2002a); 2001-2004 – (PFC, 2005b). The data is converted to constant rupees using GDP deflators.

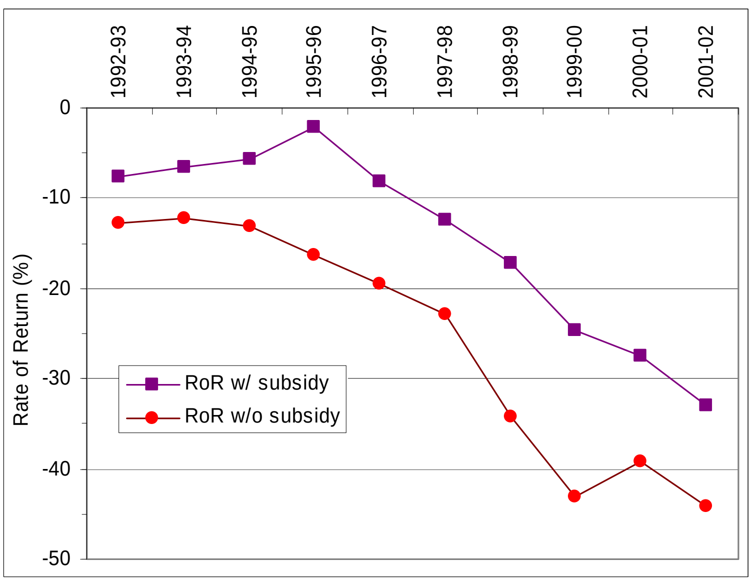

Figure 12: Rate of Return for SEBs. The rate of return for SEBs with and without State Government subvention is shown. Rate of return data for 2000-01 and 2001-02 are estimates. Source: (Planning Commission, 2002a).

The poor financial health of the SEBs led to a decreased attention to installing newer capacity at the State level (see Table 3). In 1992-93, 69% of the planned outlay was spent on new plants, whereas in 1999-00, the generation outlay dropped to 48%. As noted in the 10th Plan, "the states have practically stopped investing in new generation projects" (Planning Commission, 2002b). This lack of attention to generation at the State level is also indicated by the decreasing installed capacity, as shown in Figure 8 and Figure 9—in the 1990s, only 84 units (totaling 20 GW) were installed, in contrast to 129 units (totaling 26 GW) in the 1980s (see Table 2). Interestingly, relatively more attention was given to T&D and R&M at the State level.

Activity	8thPlan (1992-97)	Ann. Plan 1992-93	Ann. Plan 1993-94	Ann. Plan 1994-95	Ann. Plan 1995-96	9thPlan (1997-02)	Ann. Plan 1997-98	Ann. Plan 1998-99	Ann. Plan 1999-00
Generation	62	69	67	63	56	48	56	50	48
R&M	2	2	2	3	3	3	3	3	5
T&D	28	23	25	27	31	35	30	34	33
Rural Elec.	5	5	3	4	6	6	6	5	6
Misc.	3	1	2	4	4	8	5	8	9
Total	100	100	100	100	100	100	100	100	100

Table 3: Outlay in the Power Sector. The percentage of outlay for various categories is shown above for the 8th, 9th, and various annual plans. Source: (Planning Commission, 2000, 2002a)

In addition, the share of the power sector in the overall State outlays has shown a declining trend – coming down from 26% in 1991-92 to 17% in 2000-01; in contrast, Central power sector outlay as a fraction of the overall Central outlays has declined only from 13% to 10% for the same time period (Planning Commission, 2002b). Hence, Central power projects (primarily by NTPC) have dominated capacity addition in recent years.

2.4.3 Restructuring – Privatization and Regulation

While the government took a backward step with its 1991 IPP policy, it was clear that reformation of SEBs was still needed. The World Bank, which had previously engaged with the central utilities and had lukewarmly responded to the IPP policy (Dubash and Rajan, 2001), decided to focus on bringing about changes to the Indian power sector through the states. The Bank correctly noted that problems in the Indian power sector were a result of a conflict of interest "between government's role as owner and its role as operator of utilities," a problem that was not unique to India (World Bank, 1993), and promoted power sector reforms by offering financial support to states that would implement its policies for restructuring the state's electricity sector. The reforms package included (World Bank, 1993):

- Independent regulatory bodies that set tariffs for both private and public utilities through a transparent process, and balance public interest with "the need for enterprise autonomy",
- "Relaxation of restrictions on entry and exit" into the power sector to increase competition,
- Commercialization and corporatization of state-owned utilities to attract private investment,
- Separation of "generation from transmission and distribution, and encouraging cogeneration and independent power production through private investment in plants that sell to the grid", and
- Greater private-sector participation in all aspects of power sector: generation, transmission and distribution.

Orissa was the first state to embrace the World Bank reforms in 1993. It brought about legislative and institutional changes following the advice of consultants over the next five years: a regulatory commission was set up in 1996, and the SEB was split was into two generation companies and a grid management company for transmission and distribution. The unbundling process continued with the further split of the latter company into a transmission company (GRIDCO) and four distribution companies, which were to be partially or wholly privatized. The regulatory commission was quite independent and worked better than expected to protect public interest (Dubash and Rajan, 2001). However, the privatization of distribution was not successful, as distribution companies could not operate on a commercial basis because of lack of investors, ineffective competition, large technical losses and theft, high tariffs that induced further theft, and overall commercially unviable and inefficient nature of rural distribution systems (Dubash and Rajan, 2001; Tongia, 2003). The Ministry of Power now notes that "the experience of privatization of distribution in Orissa has been bitter, in spite of following the World Bank advice."[80] Nonetheless, Orissa was an important step towards reforming the power sector and reducing government intrusion in the sector.

Following Orissa's implementation of the World Bank's reforms package, many other states – Andhra Pradesh, Uttar Pradesh, Haryana, Rajasthan, and Delhi – followed suit and began experimenting with restructuring their SEBs along similar lines with support and financing from the Bank and other aid agencies. The experiences of these states have been varied, and the jury is still out on their long-term effects on the improving the power.

In the meantime, the Central government, which was keen on reforming the power sector at the national level, decided to consolidate on-going state-level efforts. On the basis of the success of the independent regulators in several states in setting rational tariffs, the Parliament passed The Electricity Regulatory Commission Act in 1998, and the quasi-judicial Central Electricity Regulatory Commission (CERC) was created soon after. The CERC has jurisdiction over setting tariffs for electricity purchased from central utilities and inter-state transmission, to formulate guidelines and advise the Central government on new guidelines and policies (CERC, 2000a). In 2000, the Central government offered financial support and incentives for states to accelerate reforms, renovate and modernize thermal and hydro stations, and improve distribution networks. In return the states had to set up independent regulatory commissions, implement full metering, and other actions (Tongia, 2003). In a final push, the Central government introduced comprehensive legislation (passed in 2003 and discussed in Section 2.5) for standardizing the regulation-unbundling-privatization structure in the power sector.

Although the entire reformation exercise was expected to revitalize the SEB by depoliticizing tariffs and by bringing elements of commercial operations into the SEBs, it is not yet clear whether these reforms will indeed bring the SEBs into profit. Even as the overall financial status of SEBs has indeed worsened, some SEBs have fared worse than others. For example, only four states—Gujarat, Delhi, Tamil Nadu and Uttar Pradesh—account for most of the 2003-04 commercial losses of SEBs.

[80] See: http://powermin.nic.in/distribution/privatization_corporatisation.htm

2.4.4 Continued reliance on thermal power

Growth in hydropower was almost non-existent throughout the liberalization and restructuring period, with generation being heavily dependent on monsoonal patterns. This lack of increase in generation remained even as hydroelectric capacity grew at an average annual rate (AAR) of 3.6%.[81] Growth in nuclear power capacity was about 3.6% AAR, although its generation grew at 10% ARR – with much of the increase occurring after 2000 as PLF remained above 70%. Nonetheless, nuclear power contributed a very small fraction to the overall capacity and generation (see Figure 2 and Figure 3).

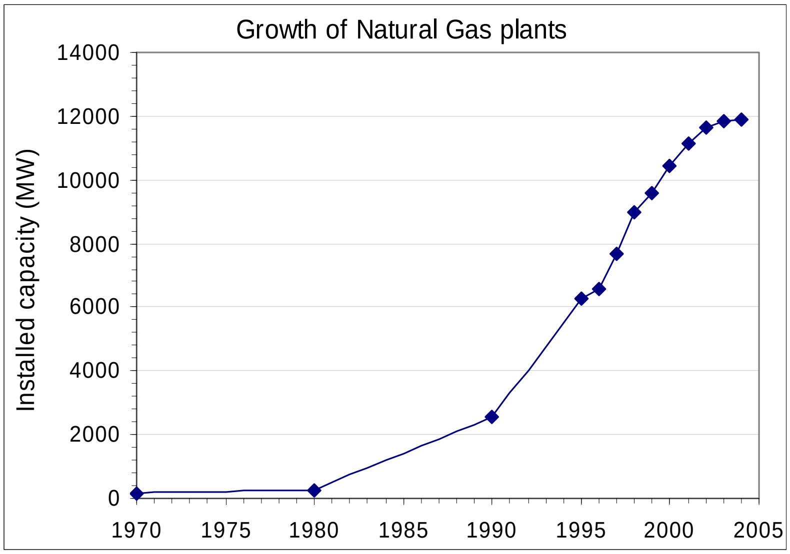

Figure 13: Growth of Gas-based power plants (1970-2004). Source: CEA general review (various years), and Press Information Bureau 2000.[82]

Thus, most of the growth in the power sector continued to come from thermal power; as a result, this sector increased its contribution to total power generation in the country during the period 1991-2003. At the same time, natural-gas-based power accounted for a significant portion of the overall additions to thermal power during this period (parallel to the worldwide trend of increased gas-based capacity in the 1990s).[83] The installed capacity of natural-gas-based power plants in India grew at a rate of 13% AAR between 1990 and 2003 (albeit starting from a low base – see Figure 11) in contrast to 3% growth of coal-based plants. Similarly, generation from

[81] This issue of reduced hydropower generation in spite of increased capacity needs to be studied further.

[82] http://pib.nic.in/archieve/factsheet/fs2000/power.html

[83] In the late-70s to the mid-80s, there were several gas discoveries in India by ONGC, particularly in Bombay High and in order to utilize this gas, the government formed a new public sector company, the Gas Authority India Limited (GAIL), to enhance gas distribution infrastructure in the country. In 1987, GAIL built India's first gas inland pipeline – Hazira-Bijaipur-Jagdishpur (HBJ) pipeline – which supplied gas to fertilizer plants, power plants, and other industrial units in six states – Gujarat, Madhya Pradesh, Rajasthan, Uttar Pradesh, Haryana, and Delhi. This pipeline and other subsequent pipeline infrastructure increased demand for natural gas in the country. In terms of power generation, natural gas has been favored for several reasons: fewer environmental impacts with reduced air, water and land pollution in comparison to coal power, higher thermal efficiency of gas turbines that can be further enhanced by combined cycle operation, lower capital cost of plants, and shorter gestation period (2 years) for construction. For these reasons, generation of electricity from natural gas was considered an effective investment in India, especially for many of the IPPs who planned on natural gas and regasified-LNG based plants (although other studies (Phadke, 2001) have indicated that domestic and imported coal-based generation is cheaper than LNG-based generation.).

natural gas grew at about 12% AAR, while coal plants grew at nearly half the rate (5%) between 1996 and 2003.

However, recently, the significant increase in global gas prices combined with uncertainty in supply expansion[84] and the present inability to increase gas supply in India has dampened the enthusiasm for natural gas. Many of the gas-based plants have now reduced generation due to lack of gas availability.

2.4.5 Moving beyond subcritical coal-power

In the 1990s, the power sector continued with its tentative efforts to diversify its coal technology options, although the focus on technology research and development remained in the shadow of sectoral reforms and the emphasis on gas-based generation (as discussed above). Nonetheless, some of the technology efforts are discussed below, with more detailed status assessments in Section 6.

2.4.5.1 Supercritical PC

An advisory sub-group for coal power technology (set up in 1989, based on the recommendations of a previous sub-group), recommended in 1990 that Indian utilities begin moving to 750 MW size units with the choice of subcritical/supercritical parameters being left to utilities (CEA, 2003). However, no units larger than the 500 MW were installed in this period and the 500 MW units were all based on sub-critical steam, despite the CEA's and the Planning Commission's calls for supercritical PC technology deployment by the late 1990s.[85] Several supercritical units were planned for installation during the 10th Plan (2002-07); however, none of them materialized as BHEL was unable to obtain technology linkages in time (CEA, 2007b). Similarly, none of the several proposed IPP projects using supercritical PC technology also materialized.[86]

A CEA committee suggested in 2003 that the next unit size for PC plants in India be in the 800-1000 MW range using supercritical steam parameters of 246 kg/cm^2 and temperatures between 568°C and 593°C (CEA, 2003). The committee also suggested that 8-10 units be installed immediately – a suggestion that is yet to be implemented. Currently, only one power plant based on supercritical PC technology (3x660 MW) is under construction at Sipat and expected to be commissioned by 2008-09. Here, the boilers will be wholly imported from the Korean company Doosan and the TG sets from Russia.[87] A second NTPC supercritical power plant at Barh has recently reached financial closure, with boilers being ordered from the Russian firm Technopromoexport and TG sets being ordered from the Power Machines Russia (CEA, 2005a).

---

[84] Between 1995 and 2003, the price of natural gas more than doubled in most major markets (see BP 2005).

[85] Many of the proposed supercritical projects ended up using the prevailing 500 MW subcritical PC technology.

[86] For example, the Power Trading Corporation (PTC) of India proposed that 6x660 MW Hirma power project use supercritical boilers. Although the project's promoters, Consolidated Electric Power (Asia) Ltd. (CEPA), were initially against the use of supercritical boilers, they later agreed to it (CERC, 2000b). However, this IPP project never happened as the promoters lost interest in it.

[87] Although BHEL in collaboration with Alstom had bid for building the Sipat supercritical power plant, NTPC opted to buy the supercritical boilers from the Korean Doosan Group and TG sets from Power Machines Russia (Airy, 2003; CEA, 2005a; Ramesh, 2005).

NTPC has been the only utility, so far, to seriously explore deploying supercritical PC technology. At the state level, utilities have been reluctant to take on the risks associated with new technologies; they also have problems with raising the required finance.[88] Hence, there is a tendency to wait for NTPC, which has both the financial and technical capacity, to 'test' new technologies, such supercritical PC, before there are attempts to implement them at the state level.

2.4.5.2 <u>Fluidized-bed combustion</u>

Despite the lack of advances in pulverized coal technology, the Indian power sector did begin to use circulating fluidized-bed (CFBC) boilers at the utility scale.[89] The key advantage for using CFBC boilers is their relative insensitivity to coal properties – these boilers can burn high-ash, high-moisture content, and low calorific value coal (including lignite), and therefore are well suited for using the poor-quality Indian coals.[90]

The first utility-scale CFBC boilers were manufactured by BHEL, which relied on a collaboration with Lurgis Lentjes Energietechnik Gmbh (LLB) of Germany for technology transfer (Gopinath et al., 2002). BHEL's CFBC boilers (2x125 MW) were used in the Surat Lignite Power Plant, commissioned in 2000.[91] Although the units had some initial problems, they are currently reported to be working satisfactorily (India Infoline, 2000). BHEL has future plans to utilize CFBC technology for coal-washery middling and other low-quality domestic coal.[92] In addition, ABB Alstom Power of Germany is currently in the process of installing 2x125 MW units using their CFBC boilers in Akrimota, Gujarat.

2.4.5.3 <u>Gasification</u>

The idea of gasifying coal and using the produced synthetic gas (syngas) for generating electricity is not new to India. Even as early as the 1970s, there were discussions and plans for using the gasification process in the electricity sector in the country. However, Indian coals, in general, are not amenable to the 'standard' gasification process using entrained-flow gasifiers because of their high ash content and high ash-fusion temperature (an issue discussed more in depth in Section 6.4.1). Hence, BHEL and the Indian Institute of Chemical Technology (IICT), Hyderabad, have focused on R&D using fluidized-bed and moving-bed gasification technologies. In the 1980s, IICT installed a Lurgi moving-bed gasifier to test Indian coals. In the early 1990s, BHEL's R&D focused on developing pressurized fluidized-bed gasification

---

[88] Furthermore, many states may not have the grid capacity to install large units – although this concern may well be reduced as the Indian grid becomes more integrated and stable. Sometimes, limitations in securing coal supply and associated transportation can also hinder projects. For example, the 3x800 MW supercritical project in Punjab has been handicapped by the railways inability to transport large quantities of required coal (Energylineindia 2005: Nov. 28)

[89] Unlike pulverized coal combustion, fluidized-bed combustion (FBC) boilers use larger particles of coal (sized at 3 mm) that are suspended in the boiler by upward flowing jets of air (hence the term 'fluidized-bed'). The residence time of the coal in the boiler is higher in FBC boilers in comparison to PC boilers and the temperature at the walls of the boiler is more uniform as result of the fluidization of the coal and air mixture.

[90] Adding limestone to the fluidized-bed can help reduce SO_x emissions, and the lower temperatures in the CFBC boiler can reduce the formation of NO_x.

[91] These boilers, which use lignite as feedstock, utilize a steam cycle at 132 atmospheres (atm) and 540 ^{o}C /540 ^{o}C (with reheat).

[92] Interview with BHEL officials (February 2005).

(PFBG) process for Indian coals. More recently, a USAID supported feasibility study indicated that a U.S.-based fluidized-bed gasification process should be suitable for Indian coals.

While much R&D effort has gone into developing technologies for gasifying Indian coal, the technology is not yet commercial and further development is currently focused on more applied R&D and building a 100 MW demonstration project.

2.4.6 Efficiency of coal-based power plants

Given the aging stock of India's power plants (see Figure 9), improving their efficiency is also increasingly recognized as an important aspect of energy policy.[93] Higher efficiency in power generation[94] is an important element of energy security, reducing environmental impacts, and lowering the cost of electricity. Furthermore, given the uncertainty in coal reserves estimates – an issue that will be addressed in more detail in Section 4.1.1[95] -- coal must be considered as an invaluable resource to be utilized as efficiently as possible in existing power plants.

Although the efficiency of coal-based power plants in India has improved in recent years, it still remains low in absolute terms and there is still plenty of room for further improvement (Shukla et al., 2004)—see Table 4. The average net efficiency (in high heating value[96]) of the entire fleet of coal power plants in the country is only 29%. The oldest units (less than 200 MW) are the worst, as indicated by the large variation from design efficiency. In spite of poor efficiencies and a low PLF, these power plants continue to be operated since they supply electricity at low costs.[97] The best power plants – 500 MW units – operate with a net efficiency of about 33%. In terms of gross efficiency, the 500 MW units operate at over 35%, although the average design gross efficiency of these units is about 38%. In comparison, the average net efficiency for the top-50-most-efficient U.S. coal-based power plants is 36%, with the fleet average being 32%.[98]

At the unit level, there is wide variation in efficiency or heat rates[99], even within a particular technology category (see Figure 14a). Furthermore, there are no fixed patterns in heat rates in terms of seasonal variations, and, in many cases, there is little or no correlation of heat rates with plant load factor (PLF). Hence, it quite clear that there is a large scope for efficiency

---

[93] See, for example, the Report of the Expert Committee on Integrated Energy Policy (Planning Commission, 2006).

[94] Efficiency improvements in T&D as well as end use are important issues, but are beyond the scope of this paper. They are however, briefly discussed in Section 8.2.1.2.

[95] Recently revised estimates indicate that there might only be about 44 billion tons of proven extractable coal reserves. See, for example, (Chikkatur, 2005; Chand and Sarkar, 2006; Planning Commission, 2006). This is in contrast to the traditionally accepted view that India as 90-96 billon tons of coal reserves (IEA, 2004e; BP, 2005; Ministry of Coal, 2006).

[96] Efficiency is calculated using the high heating value (HHV) for coal. The higher heating value of a fuel is defined as the lower heating value (LHV) plus the latent heat of evaporation of water contained in the products of combustion. The energy used to evaporate water (latent heat of evaporation) is generally unusable for power generation; hence, the use of LHV for coal is more appropriate, although energy denoted in HHV is more physically correct. HHV is more commonly used in India and in the United States. See Footnote 425 for more information.

[97] Most of the loans for these old power plants have been paid off, and therefore their fixed costs are very low. As a result, the cost of generation is determined mainly by the variable energy cost.

[98] http://www.powermag.com/plants_top.asp.

[99] The thermal efficiency of a power plant is usually measured in terms of its heat rate, which is the amount of the energy input needed to generate one kilowatt-hour of electricity. Efficiency is inversely proportional to heat rate (efficiency = 860/heat rate in kcal/kWh).

improvements in most Indian power plants, as indicated by the large gap between the actual and design efficiencies (see Figure 14b).

Unit Size (MW)	Total units operating*	Units considered for data*	BHEL make	Avg. Gross eff. (Actual)	Avg. Gross efficiency (Design)	Percent Variation**	Avg. Net efficiency (Actual)	CERC norms	PLF
500	18	18	14	35.67%	38.13%	6.90%	33.25%	35.10%	81.91%
200/210/250 (KWU)^	154	48	44	34.98%	37.65%	7.63%	31.96%	34.40%	86.59%
200/210 (LMZ)^		37	27	34.62%	36.23%	4.65%	31.66%	34.40%	78.03%
100 to 200	84	32	30	27.55%	34.87%	26.57%	24.22%	---	66.47%
Less than 100	87	32	10	25.79%	31.23%	21.09%	22.80%	---	57.65%

Source: Calculations based CEA data (CEA, 2005f).

& Average efficiency is calculated based on operation data for the period April 2000 to December 2003, as collected by the CEA

* Units operating on Lignite and those installed after 2000 are not included here

** Percent Variation is defined as (Design eff – Actual eff.)/Actual eff.

^ Design efficiency varies with technology – KWU units are based on Siemens technology, and LMZ units on Russian technology.

Table 4: Efficiency of existing power plants. Source: (Chikkatur, 2005).

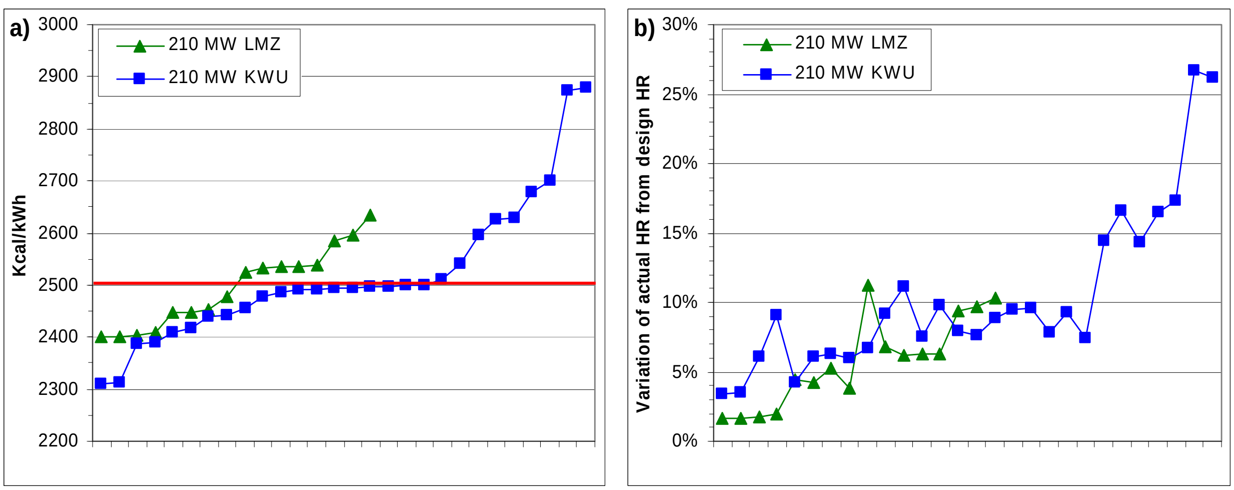

Figure 14: Heat Rate of Indian power plants. a) Shown are gross heat rates of 210 MW units of two different turbine technology categories: units with turbines of Russian (LMZ) design (triangles) and units with turbines of German (KWU) design (squares). Each data point represents the average gross heat rate of a unit, with the units from each technology category sorted by increasing heat rates. b) The average variation from design gross heat rate is shown for the same units as in (a), maintaining the same sort-order (i.e., the unit represented by the left-most data point in (b) corresponds to the unit with lowest heat rate in (a), and so on. In general, as the heat rates increase, the variation from the design heat rate also increases, albeit with some fluctuations. For each unit, the heat rate and the variation from design is based on data collected by the Central Electricity Authority (CEA) and averaged over 45 months (April 2000 to December 2003). Source: (CEA, 2005f).

The poor efficiency in India is usually blamed on a variety of technical and institutional factors such as poor quality of coal, bad grid conditions, low PLF, degradation due to age, lack of proper operation and maintenance at power plants, ownership patterns, regulatory framework, and tariff structure and incentives (Khanna and Zilberman, 1999; Shukla et al., 2004; CEA, 2005f). The quality of coal supplied to power plants has decreased significantly since the 1970s and the ash-content has increased to 40-45% (see Section 4.1.7). The use of low-quality coal increases auxiliary consumption, operation and maintenance costs and time, and reduces overall efficiency. Interesting, there is no conclusive trend yet with respect to the power plant vintage within each technology category (CEA, 2005f). The CEA (2003) has noted that lack of emphasis on efficiency during operations and maintenance of the power plants is one of main reasons for poor performance. In fact, most power plants do not accurately measure efficiencies routinely or carry out energy-audits to assess their efficiency levels (CEA, 2005f).

Many of the SEB-owned plants have higher auxiliary consumption and specific coal consumption, in comparison with Central and privately-owned plants – primarily because of poor management practices, lack of funds for maintenance, higher shut-down rates and poor response to load variations. Therefore, changes in management practices and institutional structures might also improve efficiency (Khanna and Zilberman, 1999).

It has been estimated that the efficiency of existing Indian power plants can be improved by at least 1-2 percentage points (Deo Sharma, 2004). The large gap between the actual and design efficiencies (see Table 4) also indicates that there is ample scope for efficiency improvements. Increasing efficiency by one percentage point in a power plant can reduce coal use, and corresponding air pollution and CO_2 emissions, by 3% (Deo Sharma, 2004). Furthermore, the efficiency of the power plant is also the most sensitive parameter in determining cost of generation. The cost of fuel inputs account for nearly 40-60% of the total cost of generation, with energy costs becoming more important as the capital assets of the power plant depreciate over time and loans gets repaid. Hence, the combination of the potential for significant gains in efficiency and the wide range of benefits that would result from any such improvements provide a powerful impetus for efficiency improvements of existing power plants and for deploying high efficiency plants in the future.[100]

So far, the government has mainly focused on increasing generation from power plants (in contrast to efficiency improvements) and life-extension of older power plants. The Renovation and Modernization (R&M) program has been instrumental in improving the performance of Indian power plants over the past twenty years. Since 1985, nearly 400 units (totaling more than 40 GW of capacity) have been serviced through the R&M program (CEA, 2004a). By providing technical and financial support to the cash-strapped utilities, these programs have helped power plants to maximize their generation by increasing PLF. The Life Extension (LE) program has extended the life of older power plants by 15-20 years—the economic lifetime of power plant unit is 25 years. In the 9th Plan, about 25 units were serviced under the LE program, and more than 100 units are targeted for life-extension in the 10th Plan (CEA, 2004a).

However, these government programs are not specifically aimed at improving efficiency, and hence, there remains a need for programs that focus on efficiency improvement in existing power plants (Chikkatur, 2005). One step in the right direction is the Centre for Power Efficiency & Environmental Protection (CenPEEP), a NTPC-USAID collaboration, which acts as a resource center for acquiring, demonstrating, and disseminating technologies and practices for increasing efficiency and reducing greenhouse gas emissions from power plants.

[100] For example, see (Chikkatur, 2005; Chikkatur et al., 2007a).

2.5 New institutional regime (2003–present)

2.5.1 Electricity Act 2003

As mentioned earlier, by 2000, the Indian Government had decided to consolidate the institutional reforms in the country and provide a new legal framework for the power sector. After intense debates on the initial drafts, the Indian parliament passed a comprehensive electricity legislation in 2003 – the Electricity Act 2003 (hereafter EA2003) – that replaced the 1948 Electricity Act. This new Act culminated the long power-sector reform process by requiring all SEBs to unbundle and privatize, while introducing at the same time wholesale competition, trading, and bilateral contracts with regulation. By forcing the unbundling of vertically integrated companies, the Act intends to separate generation from transmission and distribution, with the hope that generation will be subject to market competition. Generation of electricity is free from the CEA's techno-economic clearance process (except for hydroelectric power) and it only needs to meet minimal technical standards. Industry can setup captive generation anywhere and has open access to the existing electricity transmission infrastructure, as long as it pays wheeling charges. In essence, the EA2003 assumes that market forces should primarily determine capacity addition – in contrast to the earlier view that the government management of the power sector planning process was necessary for rational/economic use of resources.

Transmission utilities transmit power only upon payment of wheeling charges and do not engage in trading. Distribution utilities must obtain licenses from state regulatory agencies prior to providing electricity to consumers. In addition, multiple distribution agencies can operate in the same geographical area, with the intention being to promote competition and reduce cost of electricity for consumers. More importantly, the EA2003 creates new players in electricity supply – electricity traders. These traders, who obtain licenses from regulatory agencies, are intermediaries who can buy electricity and resell it to others. Consumers can also buy electricity directly from generation companies. For rural areas, generating companies can build plants, set up transmission and distribution infrastructure and sell power at any rate with licensing or regulatory oversight.

This new framework envisioned in the EA2003 is very different from the past. Essentially, it is a market-driven system where electricity is just another commodity that can be generated, sold, and traded in the market as determined by supply and demand. This is a dramatic shift from the earlier view that electricity is not a commodity but a tool for social progress that requires active participation of the State[101] (although it must be noted that the government has not completely abdicated its responsibility of providing power to the poor, as illustrated by its rural electrification activities).

Naturally, this radical change has created a lot of controversy and discussion over the future vision of the Indian power sector. Some analysts have openly refuted the fundamental assumptions of the EA2003. For example, Purkayastha (2001) notes that the rationale for the objectives of the earlier power sector policies—expanding power at least cost, self-reliance in

[101] For example, see (Purkayastha, 2001).

design and manufacturing, providing power at affordable rates, ensuring cheap electricity for agriculture and expanding electricity access in rural areas—are still valid today, and therefore these objectives must still form the bedrock of power sector policy. Many of the trade unions, including the Electricity Employees Federation of India, generally opposed the EA2003 because it heavily emphasized privatization (which could lead to layoffs) and on policies that were unfair to consumers.[102] Others, such as S.L. Rao (2003) and T.L. Sankar (2004), generally agree with EA2003's vision of a competitive and efficient power sector, but have had concerns regarding specific aspects of the Act, such as the provisions of open access, surcharges and cross-subsidies, role of regulators, and the impact on SEBs during the transition period.

A recent series of articles examining the international experience in electricity-sector restructuring (Economic and Political Weekly, December 10, 2005) has shown that it is not a simple affair as initially envisioned in the 1990s; its underlying complexities, accentuated by recent problems, demand an open debate on the value of restructuring in the Indian context (Dubash and Singh, 2005a). For example, it is not yet clear as to how the simple unbundling required by the EA2003 will impact distribution issues, particularly in reducing T&D losses. While the vision of EA2003 might indeed be "bright", there are still electricity shortages, problems with coal supply and quality, and lack of electricity access to a vast number of people. There is no simple answer to the question of how changes resulting from EA2003 will impact these issues.

However, some of the discussions on the EA2003 have led to new ideas on the future of the Indian power sector. For example, T. L. Sankar (2002) has provided a new paradigm of the power sector wherein he emphasizes the importance of providing access to cheap power for rural consumers, rather than focusing on industrial and commercial sectors. The key idea behind Sankar's plan is to dedicate specific generators for specific consumers: low-cost hydroelectricity and older coal based plants would supply electricity to agricultural pumps and rural electricity, whereas the more expensive and newer coal- and gas-based power would supply industry and commercial consumers.[103]

2.5.2 Beyond EA2003 – the future

Nonetheless, with the EA2003 being passed and its various policy aspects being implemented in the country, the focus within the power sector will now shift to deeper and more complex issues: ensuring competition and independent regulation, minimizing monopolization, expanding the availability of affordable power to the poor, improving management of generation and distribution utilities, various technology issues in different segments of the power sector, etc. This new stage—'beyond EA2003'—will be marked by how the different elements of the Indian power sector (and more broadly the energy sector) will respond to these various challenges given the history of the sector and its existing constraints. Many of the decisions and policies will need to occur in an integrative and transparent fashion.

[102] See letter by Mr. B.S. Meel (General Secretary -- Electricity Employees Federation of India). http://www.eefi.org/ebill2001.htm

[103] Reddy (2002) has compared and contrasted Sankar's proposal with the framework under Electricity Act 1948 and Electricity Act 2003. He concludes that Sankar's proposal is indeed pro-people, unlike the EA2003 framework.

3 Challenges

Looking forward, the Indian coal power sector faces a number of different challenges. While some of these challenges are similar to those in the past, others are of more recent origin. From our perspective, the four key challenges are:

1. Continuing (and even more pressing) need for expanding energy availability
2. Energy security
3. Local environmental protection
4. Global environmental issues

3.1 Urgent need for further expansion of energy availability

3.1.1 Need for development

Energy services provide basic needs such as cooking, heating, and lighting, as well as fuel a range of industrial activities and sustain today's transportation and communication systems. Thus, the limited availability of energy often constrains human and economic development.
The lack of modern energy services can prevent the realization of basic human needs, including education, sanitation, health and communication.

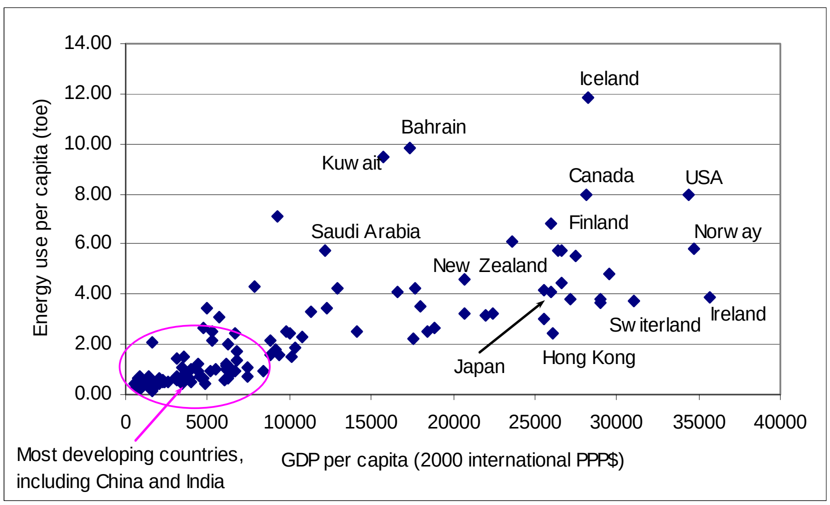

Figure 15: Energy Consumption per capita vs. GDP-PPP (2002). Source: (World Bank, 2002).

Generally, as countries become richer, energy consumption per capita rises correspondingly to satisfy increasing demand for energy services from both the industrialization process and the rising living standards. Thus, there is a broad correlation between per-capita GDP and per-capita energy consumption[104] (see Figure 15), as well as between the Human Development Index and per-capita energy consumption across countries (see Figure 16). Most developing countries, including India, have very low per capita energy consumption and their level of economic and human development (measured by GDP-PPP and the UNDP's Human Development Index, respectively) is quite low.

[104] It should be noted that there is no fixed relationship between energy consumption and GDP. For example, among industrialized countries, Japan and European countries are less energy intensive than the United States and Canada. See Figure 15.

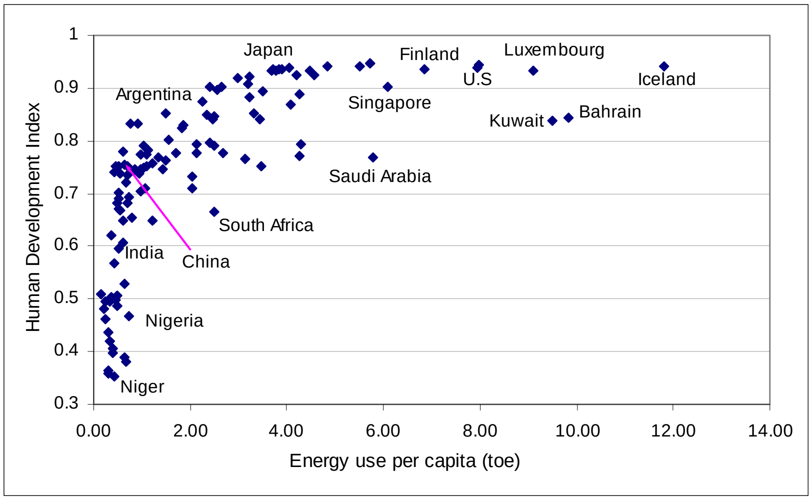

Figure 16: Human Development Index vs. energy consumption per capita (2002).
Source: (World Bank, 2002; UNDP, 2004a).

Table 5 presents the status of the Indian energy sector on a number of key indicators and compares it to that of other countries. As can be seen from the table, India has extremely low levels of energy use on a per-capita basis, in comparison to not only industrialized countries but also the global average and other industrializing countries such as China. The total primary energy supply (TPES) in the country was 0.51 toe in 2002 – this is almost one-tenth of the OECD average, less than a third of the global average, and almost half that of China.

	TPES/capita (toe)		TPES*/capita (toe)		Electricity/capita (kWh)		Electricity/GDP (MWh/million 2000 international PPP$)		GDP/capita (2000 international PPP$)	
	1990	**2002**	**1990**	**2002**	**1990**	**2002**	**1990**	**2002**	**1990**	**2002**
India	0.43	0.51	0.22	0.31	275	421	161	165	1702	2555
China	0.78	0.96	0.60	0.79	511	1184	320	270	1597	4379
US	7.72	7.94	7.70	7.92	11713	13186	413	383	28391	34430
Japan	3.61	4.06	3.61	4.06	6609	8223	282	316	23442	26021
Global	1.64	1.65	1.46	1.47	848	888	327	310	6312	7649
OECD	4.34	4.67	4.20	4.52	6771	8046	338	331	20115	24339

Table 5: Indicators of energy and electricity use in various countries. TPES refers to total primary energy supply and TPES* refers to TPES excluding renewable and combustible sources. Source: (World Bank, 2002; IEA, 2004a, 2004b).

Furthermore, coal is the dominant source of commercial energy supply, in India and China (see Figure 17), and unlike the United States, oil accounts for a much smaller fraction of overall supply. In addition, biomass and combustible renewables and waste are estimated to account for almost 40% of India's total primary energy supply—worldwide, the corresponding number is only about 11%. Furthermore, in the Indian context, these sources are generally utilized in open combustion in households (mainly in cook stoves) or smaller enterprises (as sources of process heat); thus, a substantial fraction of the country's population is reliant on non-modern, traditional energy services.

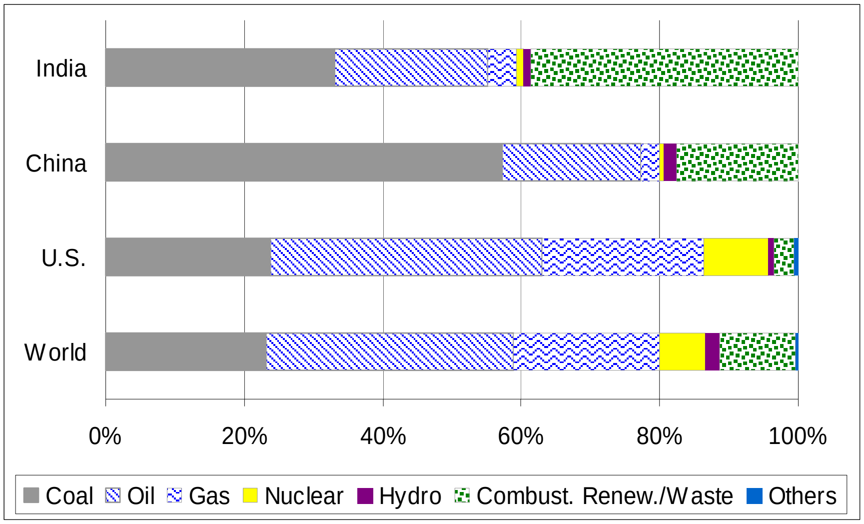

Figure 17: Breakdown of total primary energy supply (2002). Source: (IEA, 2004a, 2004b).

The picture is not that much better in terms of electricity use – the per-capita electricity use in India was 421 kWh in 2002, which is just over one-third that of China and almost one-twentieth that of the OECD average. Even when electricity use is normalized with respect to GDP, we see that Indians have much lower availability of electric power compared to other countries. In fact, India has long suffered from an insufficient supply of electricity in relation to the demand – in 2005, the total shortage of power was estimated to be 6-8%, and the peak shortages were as high as 11-12%. The quality of power supply in the country is also very poor, with unstable voltages and routine frequency excursions. In fact, the lack of adequate and reliable supply of power is often cited as a critical constraint to industrial development (World Bank, 1999).

Moreover, it is important to note that energy is not an end in itself, and it only provides the means towards reaching social and developmental goals. In order to meet developmental goals, the focus cannot narrowly be on increasing overall supply of energy, but on enhancing the availability of energy services. Given India's large rural population, it is particularly important to ensure fair access and availability of energy and energy services in rural areas, especially for meeting basic needs (Goldemberg et al., 1988). Therefore, even as primary energy supply is increased, one must be concerned about its efficient conversion to useful forms and its equitable distribution.

3.1.2 Expanding power demand

As countries develop and modernize, electricity, as a modern energy carrier, plays a central role in the provision of energy services such as lighting and cooling, and enables activities such as the operation of industrial machinery, computers, and electronics. In fact, it would be fair to say that electricity lies at the heart of most industrial activity. The ease with which it can be transmitted long distances also provides enormous advantages, as does its ability to be used locally without environmental pollution.[105] Hence, there generally is a rapidly increasing demand for electric power from the residential, commercial, and industrial sectors in developing countries.

[105] Low-frequency electric and magnetic fields (emf) that radiate from electrical wires and power-lines could have biological and human health impacts, although current science indicates only a slight increase of cancer rates in children from exposure to magnetic fields at power-frequencies larger than 0.4 micro-Tesla (McKinlay et al., 2004).

Consistent with this general trend, the demand for electricity in India is also projected to increase drastically over the next 20-30 years. The Government has relied on various short-term and longer-term projections to assess future demand growth in the country and the required electricity supply from the power sector.[106] Relying on the 16th Electricity Power Survey, the Ministry of Power predicts that the demand for utility-generated electricity will more than double from about 520 TWh in 2001-02 to about 1300 TWh by 2016-17, with an annual growth rate of about 6-7% for electricity consumed (CEA, 2000). The Planning Commission, relying on demand estimates calculated using GDP growth rates, expects the demand would nearly triple from 2001-02 to 2016-17 for an 8% annual GDP growth rate, and longer term predictions indicate demand to be around 3600-4500 TWh by 2031-32 (Planning Commission, 2006).[107] Similar projections for demand have been calculated using regressive econometric models using GDP as an independent variable, as suggested by TERI, NCAER, and others (CEA, 2004a).

Based on these projections, the government calculates shortage/excess of base and peak capacity with respect to demand, and the necessary future installed capacity to meet projected demand. Despite increases in the installed capacity, energy shortages of 6-12% and shortages of peak demand between 11-20% since 1991,[108] although the shortages have eased a bit recently. Based on the demand projections of the 16th Electric Power Survey, the government in 2001 announced that 100 GW of new capacity needs to be installed in the 10th and 11th plan periods (2002-2012) to meet its goal of providing "reliable, affordable and quality power supply for all users by 2012" (Ministry of Power, 2001). The Planning Commission reaffirmed this requirement and noted that the installed capacity needs to be about 800-1000 GW[109] by 2031-32, depending on GDP growth (Planning Commission, 2006).

Other researchers have corroborated the government's projections showing rapid growth of installed capacity and electricity generation in India. Gupta *et al.* (2001) have used a RAINS-ASIA model to predict that the overall generation of electricity in India needs to quintuple in 30 years from 1990 to 2020. Shukla and collaborators have made longer predictions up to 2100, when they expect India to be generating ten times as much as electricity compared to 1995 – 4300 TWh in 2100 from 420 TWh in 1995 (Rajesh et al., 2003).

While the large projected demand and required electricity supply seems quite daunting, many have pointed out that the government's projection of future electricity demand is too optimistic, and that it does not properly taking in account future technological improvements and reductions in system inefficiency. Because of current high inefficiencies in the transmission and

[106] The Government projection of demand has been based on a partial end-use method, where historical consumption by end-users and generation by utilities are projected into the future using time-series analysis of past trends, including projected transmission and distribution losses (CEA, 2004a).
[107] It is very important to assess the validity of the various assumptions underlying these long term projections. For example, the Ministry of Power assumes a constant elasticity of energy consumption with respect to GDP, whereas the Planning Commission assumes step-wise falling elasticity from 0.95 to 0.78 between 2004 and 2031. A regression analysis of generated electricity between 1990-91 to 2003-04 indicates that the elasticity of total per-capita electricity generated with respect to GDP was 1.06 (Planning Commission, 2006).
[108] Various Annual Reports of Ministry of Power.
[109] This includes non-utility (captive power) installed capacity.

distribution systems[110], it is difficult to predict the necessary installed capacity to meet demand, especially as it is likely that the inefficiencies will be reduced in the future. Despite optimistic projection of future demand, it is important to note that growth rate for utility-electricity consumption has been decreasing. Since 1991, the consumption of electricity has increased at an averaged annual rate of 5%, whereas in the 1950s and 60s the annual growth rate averaged about 12%. Much of this reduced growth could be a result of industries moving away from the grid to generating their own electricity (Purkayastha, 2001).[111] Although the government has been encouraging captive generation, it is still using previous high growth rates for industrial power consumption from utilities to calculate future demand. Purkayastha (2001) has correctly noted that growth of electricity is not independent of its cost, and faced with increasing tariffs, the consumption of grid-based electricity will reduce and people will resort to theft to meet their needs. The addition of new capacity itself might increase tariffs because the high capital and financial costs will be passed onto the consumers,[112] and further reduce demand.

Thus, it may be best to consider the government data as an upper bound for future growth in the power sector. But even in such a case, it is clear that India's demand for electricity will rise rapidly in the next 20-30 years. Given the numbers involved, it is clear that any growth in installed capacity must be accompanied by concurrent growth and (efficiency) improvements in transmission and distribution systems, and in the overall financial well-being of the sector.

3.1.3 Continuing reliance on coal

The projected rapid growth in electricity generation over the next couple of decades is expected to be met by using coal as the primary fuel for electricity generation. Other resources are uneconomic (as in the case of naphtha or LNG), have insecure supplies (diesel and imported natural gas), or simply too complex and expensive to build (nuclear and hydroelectricity) to make a dominant contribution to the near-to-mid term growth.

As in the past, there is once again an increased effort to push for hydroelectricity. Keeping in mind that only about 18% of the 84 GW 'economic potential' of the Indian river systems has been developed and with 6% more currently under development (CEA, 2004a), the Government of India has now a well-publicized "50,000 MW Hydroelectric scheme" to utilize the remaining economically viable hydro-power potential in the country. However, as in the past (section 2.3), there are a number of problems with developing hydroelectricity in India, including shortage of funds, lack of interest by the private sector, inter-state water use conflicts, low electricity demand in regions of high hydroelectricity potential combined with a lack of suitable transmission infrastructure,[113] long gestation periods, geological uncertainty in the Himalayan regions, high environmental impacts, and problems of rehabilitation (CEA, 1997). As discussed earlier in section 2.4.4, the growth of electricity generated using water has been stagnant in the recent

[110] Currently, there is potentially a high latent demand for electricity both in urban and rural areas. This demand is currently unmet because of distribution problems and lack of availability and accessibility.

[111] Some of the high growth in the 50s and 60s could have satisfied the latent residential and commercial needs, which could have also led to reduced demand in the later years.

[112] The cost of electricity from new power plants is higher than the cost from older power plants, because newly installed power plants have higher asset value in comparison to the older plants which are discounted, and they have higher financial costs because of their loans.

[113] 27 GW out of the 50 GW in the new hydroelectricity scheme are located in Arunachal Pradesh, yet electricity demand in this state was estimated to be only 84 MW in 2000 (CEA, 1997, 2005d).

years, despite the more capacity being added. Thus, the complex problems associated with hydroelectricity might well continue to limit the growth of hydroelectricity in India, despite the government's best efforts.

Liquid fuels such as heavy oils have limited use in the power sector for economic and environmental reasons. Distillates such as naphtha, high sulfur diesel (HSD), and other condensates are either expensive or too polluting for large-scale use. Although domestic distillates are now allowed for use in the power sector, they are used in only niche applications. Given the limited domestic oil reserves (790 million tons in 2004-05[114] – 0.5% of world reserves) and production (34 million tons in 2004-05[114]), India is forced to import over three-quarters of its petroleum consumption. The costs of importing oil are significant and uncertain due to the recent rise of crude oil prices (which are not expected to decline to the low levels of the mid-1990s) and volatility in the world oil markets – the import costs are also a major drain on the country's foreign exchange reserves. Although use of natural gas and regasified LNG in the power sector is increasing, particularly in the private sector, its long-term availability and cost are uncertain. Currently, existing power plants are experiencing low load factors because of paucity of domestic supply.[115] Similar to oil, domestic reserves are very limited (1100 billion cubic meters in 2004-05[114] – 0.6% of world's reserves). Furthermore, the high cost of natural gas and of LNG handling facilities is another crucial factor that is limiting the growth of the gas-based power generation.[116] Nonetheless, the use of natural gas in the power sector is projected by Planning Commission (2006) and others to increase in the short-to-medium term.

The potential for nuclear power development is also not high in India in the short-to-medium term, although it is expected to play a major beyond 2050 (Planning Commission, 2006). In 2003, nuclear power accounted for only 3.6% in terms of electricity generated (CEA, 2004a). Limited domestic natural uranium resources and various international restrictions have held back the Indian nuclear power industry in terms of fuel supply and technological improvements (Gopalakrishnan, 2005). Hence, future growth in this sector is dependent on the development of indigenous technology based on thorium, which more readily available in the country, in fast breeder reactors.[117]

Installed capacity of power plants based on renewable sources, such as biomass (combustion and gasification), solar photovoltaics, and urban and industrial waste, are relatively small and used mainly in niche applications; even wind power, which has shown significant growth in the last decade, is concentrated in a few states where commercial-scale wind resources exist and it contributes only about 0.5% of the total power generation in the country. These 'non-

[114] See Ministry of Petroleum and Natural Gas website. http://petroleum.nic.in/petstat.pdf

[115] For example, see: "NTPC opts for liquid fuel to meet gas shortage" Business Standard May 5, 2005; "Gail asks AP-based IPPs to look for alternate fuel" Financial Express May 9, 2005; "CAG raps govt for power generation mess" Business Standard May 20, 2006.

[116] For example, see: Mamata Singh, "Gas cost to fuel power price" Business Standard May 7, 2005.

[117] The recent U.S.-India nuclear accord, if ratified, might ease the dependence of the Indian nuclear power sector on indigenous fuel supply and technologies. India could get access to the worldwide uranium markets and technologies. However, there is considerable debate regarding the accord's benefits (or lack thereof) to the Indian nuclear industry and its growth.

conventional' energy sources form about 7200 MW (5%) of installed capacity.[118] Much of this installed capacity does not have high load factor, as only about 4600 GWh (0.08%) of electricity was produced with these non-conventional energy systems (CEA, 2006a). Although their increased use is necessary and important, they are unlikely to play a significant role in the power sector, at least in the near-to-medium term.

Many academics have also projected coal as the main fuel for the power sector. Gupta *et al.* (2001) have used a RAINS-ASIA model to predict short term electricity growth up to 2020. Under business-as-usual conditions, they predict the production of electricity from coal to increase from 190 TWh (out of 290 TWh in total) in 1990 to 870 TWh (out of 1440 TWh) in 2020. Shukla and collaborators (Rajesh et al., 2003) have used modified MARKAL and AIM/ENDUSE models to project that coal-based capacity will increase to more than 450 GW by 2100, out of 900 GW. Generation of electricity by coal is expected to be around 70% of total generation at that time.

Initial projections by the CEA (2004a) indicated that about 40 GW out of a total of 100 GW of new capacity would be based on coal and lignite in the short-term (2002-2012; 10th and 11th Plans). The original target for capacity addition in the 10th Plan (2002-2007) is shown in Table 6 and the feasible capacity addition in the 11th Plan (2007-2012) is shown in Table 7. As of March 31, 2007, only about 9.5 GW of coal and lignite based capacity had been achieved, which is half of the initial target of 20.5 GW.[119] Given that the total capacity installed under the 10th Plan is lower than expected,[120] more coal-based capacity is planned for the 11th Plan—currently, about 50 GW of coal-based capacity is on the shelf of projects for the 11th Plan.[121] Based on the current set of planned projects, only about 17% of the new capacity is based on supercritical PC technology in the 11th Plan (see Table 8). Furthermore, nearly all of the supercritical technology is expected to be installed in the Central sector.

Sector	Hydro	Thermal			Nuclear	Total
		Coal & Lignite	Gas	Liquid Fuel		
Central	8742	12290	500	0	1300	22832
State	4481	5660	922	94	0	11157
Private	1170	2603	3328	20	0	7121
Total	14393	20553	4750	114	1300	41110

Table 6: 10th Plan capacity addition (Original Target). Source: (CEA, 2004a).

[118] Source: Annual Report 2005-06 of the Ministry of Non-Conventional Energy Sources. According to CEA (2006a), the installed capacity of wind, biomass power, biomass gasifiers, and urban and industrial waste is 3960 MW in March 2005, including both utilities and non-utilities.
[119] http://cea.nic.in/thermal/project_monitoring/1.pdf; accessed May 3, 2007.
[120] By March 31st 2007, the actual installed capacity in the 10th Plan was only 21 GW (nearly half of the original target of 41 GW). See http://cea.nic.in/thermal/project_monitoring/1.pdf; accessed May 3, 2007.
[121] See: http://cea.nic.in/thermal/Shelf_of_Thermal_Power_Projects_11th%20Plan.pdf; accessed March 23rd, 2007.

SECTOR	HYDRO	TOTAL THERMAL	THERMAL BREAKUP			NUCLEAR	TOTAL (%)
			COAL	LIGNITE	GAS/LNG		
CENTRAL	9,685	23,810	22,060	1,000	750	3,160	36,655 (53.2%)
STATE	2,637	20,352	19,365	375	612		22,989 (33.4%)
PRIVATE	3,263	5,962	5,210	0	752		9,225 (13.4%)
Total	15,585	50,124	46,635	1,375	2,114	3,160	68,869 (100%)

Table 7: Feasible 11th Plan (2007-2012) capacity addition targets. Source: (CEA, 2007b).

	Central		State		Private		Total	
Unit Type	**Number**	**GW**	**Number**	**GW**	**Number**	**GW**	**Number**	**GW**
SCPC 660/800	10	6.6	1	0.8	1	0.7	**12**	**8.1**
PC 500	27	13.5	23	11.5	3	1.5	**53**	**26.5**
PC 300			4	1.2	6	1.8	**10**	**3.0**
PC 200-250	9	2.3	25	5.9	5	1.3	**39**	**9.4**
PC 110/125	4	0.5	3	0.4			**7**	**0.9**
Total	**50**	**22.8**	**56**	**19.7**	**15**	**5.2**	**121**	**47.8**

Table 8: Unit type and capacity for 11th Plan coal-based projects by sector. This includes both coal and lignite based units. Source: Based on data given in CEA (2007b).

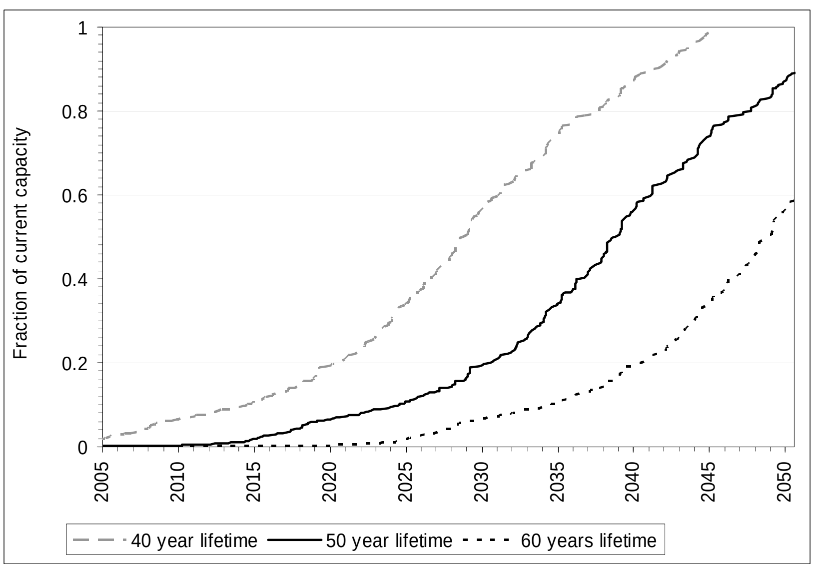

Figure 18: Replacement Capacity (as fraction of current capacity). Shown are the capacities of coal-based power plants that would need to be replaced, as fraction of current capacity.

In addition to the new coal capacity that is likely to be added in the near future, there is still the large number of coal plants that would need to be replaced as the old power plants near the end of their life. Typical life of a power plant can vary anywhere between 40-60 years, depending on how well they are maintained. In India, most of the old power plants installed prior to the 1950s have been shutdown and in some cases replaced with new plants. While the life of power plants can be extended (as in the Life Extension program), the high cost of operation and maintenance combined with the requirement to meet tighter environmental standards will require shutting down old plants or repowering them with new technologies. Figure 18 shows likely the amount of current capacity that would need to be replaced in the future assuming different lifetimes for these plants. As shown in Figure 9 most of the thermal capacity in India was installed between 1980-1990, and hence by 2030-40, a significant fraction of the current coal capacity will likely be replaced—nearly 90% of the current plants will have be replaced by 2050, assuming a 50 year lifetime for power plants.

3.2 Energy Security

Energy and energy services underpin the provision of basic human needs, as well as all economic activity. Hence, the availability of adequate, reliable, diverse, and economically viable fuel supplies, i.e., energy security, is a key goal of a country' energy policy. There are many definitions of energy security,[122] and it can mean different things to different people. Most industrialized countries relate to energy security in the context of high costs and supply constraints of oil and natural gas. However, energy security in developing countries relates to the availability and security of *all* fuels (not just oil) for all citizens, including the availability and accessibility of non-commercial energy sources, such as firewood, for the rural poor.[123] The latter issue is particularly relevant to developing countries with a large number of people who do not have access to clean, reliable energy sources (electricity, LPG, kerosene, etc.). In this sense, creation of effective distribution networks and price of clean energy in rural areas is an important energy security issue. Another important energy security issue is improving and increasing distribution networks for clean energy sources; for example, electricity grids are poorly maintained and are often neglected in many rural and peri-urban areas.

For the generation side of the Indian power sector, which relies heavily on fossil fuels, it is important to view energy security in context of domestic and global availability of fossil fuel resources and demand for them.[124] Table 9 provides an overview of the availability, consumption and production of fossil fuels in India, as well as in the world, the United States, and China.[125] Although the availability of a large domestic fossil fuel resource-base is ideal for enhancing energy security, there must be a corresponding level of investment (both human and financial) to efficiently extract the resource, convert them into useful forms of energy and supply these to consumers. India has also been increasing its energy imports—nearly 30% of India's total primary commercial energy supply (TPCES) in 2004-05 was imported; in contrast, only 18% was imported in 1991 (Planning Commission, 2006). Moreover, energy imports are projected to increase in the future – not only for oil and gas, but for coal as well. The need for these increased imports will occur at a time when there is greater worldwide competition and demand for these resources. Hence, India will need to strategically position itself (economically, politically, diplomatically, and militarily) to ensure a stable and secure supply of fuels for its energy sector.

---

[122] According to the UNDP (2004b), energy security can be defined as the ability to access adequate, affordable, reliable, and diverse energy sources required for a country's development needs.

[123] For example, the recent IEP report has defined energy security as being able to supply "lifeline energy" to all citizens as well as meet their effective demand for safe and convenient energy at affordable costs within a reasonably expected confidence levels (Planning Commission, 2006). The concept of lifeline energy ensures that the poor in the country are not ignored; although, the Planning Commission has not yet fully defined or quantified the notion of lifeline energy.

[124] The recent Indo-U.S. civilian nuclear pact is also considered to be part of India's energy security strategy, as plutonium produced from nuclear reactors based on imported uranium can be used with fast-breeder reactors that can use the country's vast thorium resources.

[125] The United States is the largest consumer and China is the fastest-growing consumer of fossil fuels. The actions taken by these two nations will impact India's strategic energy interests, and hence India should carefully tune its energy policies by considering the impact of energy policies of these two countries.

	Oil				
	Proved Reserves Billion Barrels (% of World)	R/P ratio* Years	Annual Consumption Million Tons (% of World)	Annual Production Million Tons (% of World)	Import % of Consumption
World	**1194 (100%)**	**41**	**3799 (100%)**	**3865 (100%)**	
U.S.	29.3 (2.5%)	11	949 (25%)	329 (8.5%)	65%
China	16.0 (1.3%)	13	334 (8.8%)	174 (4.5%)	48%
India	**5.6 (0.5%)**	**19**	**120 (3.2%)**	**37.9 (1%)**	**68%**
	Natural Gas				
	Proved Reserves Trillion cubic meters (% of World)	R/P ratio Years	Annual Consumption Million tons of oil equiv.	Annual Production Million tons of oil equiv.	Import % of Consumption
World	**179 (100%)**	**66**	**2425 (100%)**	**2433 (100%)**	
U.S.	5.5 (3.1%)	10	581 (24%)	486 (20%)	20%
China	2.2 (1.3%)	54	37.1 (1.5%)	36.9 (1.5%)	0.5%
India	**0.92 (0.5%)**	**31**	**29.5 (1.2%)**	**27.1 (1.1%)**	**9%**
	Coal				
	Proved Reserves Billion Tons	R/P ratio Years	Annual Consumption Million tons of oil equiv.	Annual Production Million tons of oil equiv.	Import# % of Consumption
World	**909.1 (100%)**	**164**	**2799 (100%)**	**2751 (100%)**	
U.S.	246.6 (27.1%)	245	566 (20%)	568 (21%)	-0.4%
China&	114.5 (12.6%)	59	985 (35%)	1007 (37%)	-2%
India	**44 (5%)**	**110**	**204 (7%)**	**191 (7%)**	**6%**
* Reserve-to-Production (R/P) ratio is the length of time current reserves would last if production were to continue at current level.					
& Includes Hong Kong and SAR					
# Negative numbers indicate export					

Table 9: Fossil Fuel Reserves 2004. Adapted from (BP, 2005). Information about coal in India is based on calculations based on various sources: (CMPDIL, 2001; BP, 2005; Chand and Sarkar, 2006).

3.2.1 Oil and Natural Gas

India's domestic oil and natural gas reserves are very minimal (about 0.5% of world reserves) and over three-quarters of India's petroleum consumption was met through imports in 2004-05;[126] petroleum and related products account for about a quarter of India's TPCES (Planning Commission, 2006). Furthermore, the existing domestic oil and natural gas reserves will likely to be consumed sooner than the R/P ratio noted in Table 9, since demand will inevitably rise and domestic production will be ramped up to meet demand. Clearly, today's oil situation in India is not conducive to being energy secure.

[126] See Ministry of Petroleum and Natural Gas website. http://petroleum.nic.in/petstat.pdf

In some ways, the energy situation today is akin to the mid-1970s when the supply of oil was limited by the OPEC countries. Although the oil price spikes of the 1970s were created by an artificial squeezing of supply, the current limitation of supply could be more fundamental. Many analysts claim that the production of oil and natural gas are limited by resource availability, resulting in an imminent (or even recently passed) peak in the production of oil – popularly termed as 'peak oil' (see, for example, (Deffeyes, 2001; Simmons, 2005)). But others claim that we will be able to better exploit existing resources and tap new unconventional resources to meet expanding needs, as we have done in the past; see, for example, CERA (2005).

Nonetheless, there are several key aspects of oil security that do warrant caution for India:

- Unlike in the 1970s, India's dependence on oil is now very high, and use of oil is more widespread in the country. Global oil demand also continues to grow, in large part because there is no easy substitute for its use in transport, which is the major source of oil demand worldwide.
- Much future oil and natural gas is expected to come from Middle East and Former Soviet Union countries, as most of the oil and natural gas is concentrated in that region (BP, 2006). This concentration of hydrocarbon resources in the Middle East could lead to greater political, economic and military conflicts as nations vie for the limited supply – leading to a supply risk for India.[127]

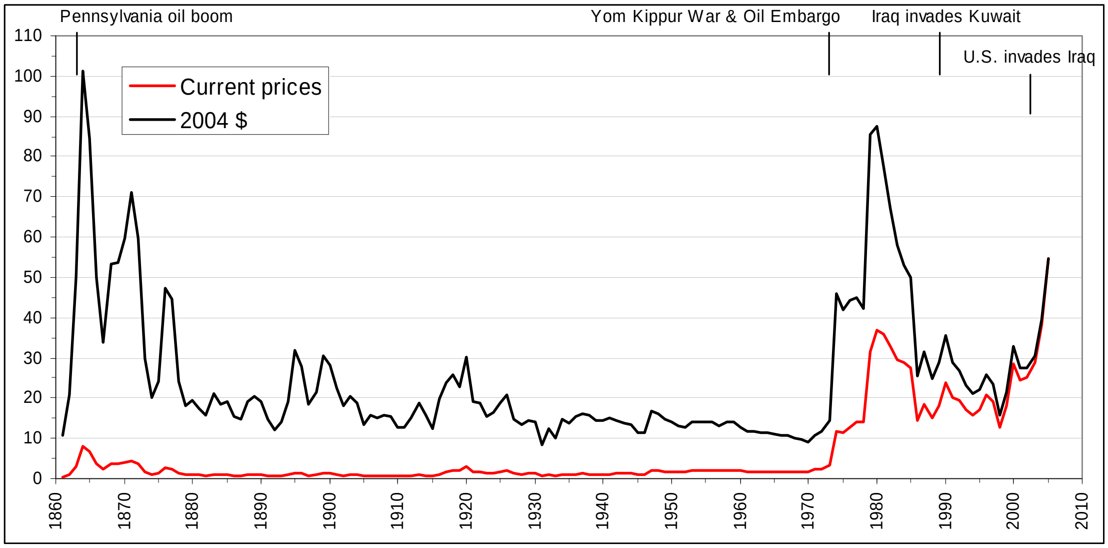

Figure 19: Price of Oil (1861-Present) in current and 2004 dollars. Data from 1861-1944 is based on US average; 1945-1983 on Arabian light posted on Ras Tanura; and 1984-2005 on Brent dated. Source: (BP, 2006).

- The increasing price of oil and natural gas poses serious problems for the balance of payments, as well as for consumers. The hydrocarbon markets are quite strained, with the price of oil hovering around $70 per barrel, nearly double the $30 per barrel (in real dollars) price in the 1990s (Figure 19). Natural gas, which remained between $2-3 per million BTU (mmBTU) for most of the 1990s, has also doubled with prices around $5-6 per mmBTU (Figure 20). It is not just average prices, but the fluctuations in prices also

[127] This kind of disruption is also of concern for domestic sources; for example, coal supplies could be disrupted due to strikes or lack of investment in railways and ports.

adversely affect the economy. Furthermore, as more countries industrialize and integrate themselves into the modern globalized economy, there will be a corresponding increase in oil demand. Thus, India could soon find itself with fewer and more expensive supply options to meet its hydrocarbon needs.

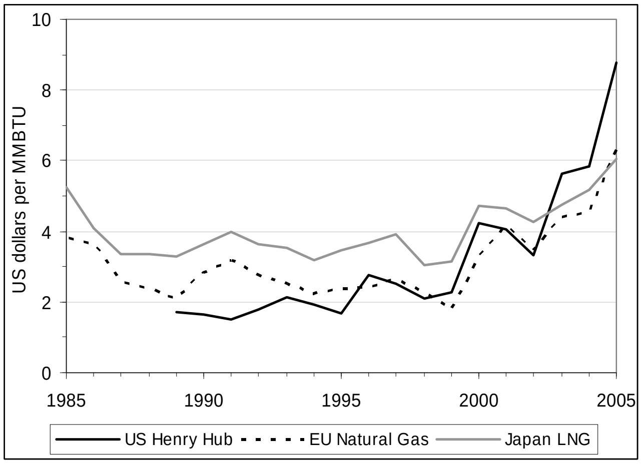

Figure 20: Price of Natural Gas (1985 – 2005). Source: (BP, 2006)..

In order to partial allay some of these problems with oil-supply, India has begun to acquire oil fields abroad through ONGC-Videsh Limited, a subsidiary of the Oil and Natural Gas Corporation (ONGC) created in 1996. By March 2006, the company had a total of about 200 MMT of reserves of oil and gas in Vietnam, Sudan, Russia, and Syria, with a production of 6.3 MMTOE in 2005-06.[128]

Coal-to-liquid technologies to produce fuels for transportation can also be considered as part of a strategy to reduce dependence on oil imports; however, the consequences of the large-scale use of these technologies must be more critically assessed, especially given the uncertain nature of coal reserves (see below).

3.2.2 Coal

In contrast to hydrocarbons, India does have large coal resources, although it has recently become clear that there are enormous uncertainties regarding the exact amount and nature of coal reserves in India, which in turn leads to questions about the level of domestic coal production that India can sustain in the near and long term. This issue is discussed in more detail in section 4.1.1. The current best guess, based on information from CMPDIL (2001), indicates that India has about 44 BT of reserves, out of about 250 BT of resources. Out of this 44 BT, only about 18 MT of virgin reserves is available for new mining projects (with the rest 26 MT being already allocated for mining projects). However, the demand for coal is expected to be quite high in the short-to-medium term. With the large number of coal-based thermal power plants expected to come online, coal consumption in the power sector is expected to be about 585 MT by 2011-12 (CEA, 2007b) and 1-2 BT by 2031-32 (Planning Commission, 2006); see Figure 29. Therefore, there could be significant problems with domestic production trying to cope up with upcoming demand.

[128] See: http://www.ongcvidesh.com.

The problems with domestic coal production are already evident as many power plants across the country are experiencing critically low levels of coal stock (see section 4.1.2). While the current situation might be viewed as temporary, many analysts are predicting that the gap between domestic coal supply and coal demand (for power and other industries) is expected to increase in the coming years, and that options other than domestic coal must be used to bridge the gap between demand and domestic supply of coal (Chand and Sarkar, 2006).

Hence, it is expected that India will increase its coal imports in the future. India is already importing significant amounts of coal (see Figure 30), amounting to about a third of its coking-coal demand, and 3% of non-coking coal needs. In 2003-04, nearly 24 MT of coal (including both coking and non-coking) was imported from Australia, Indonesia, South Africa, and China (IEA, 2002a; Ministry of Coal, 2004). The price of coal imports, which was reasonably stable, has recently experienced a high degree of volatility (see Figure 21). While such price volatility might be a short-term problem, it is an important issue for India as it prepares for greater imports.

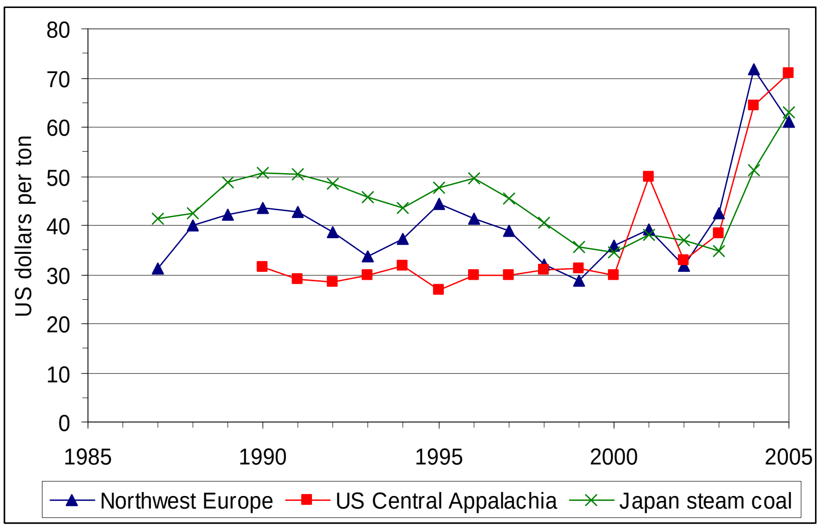

Figure 21: Price of Coal in International Markets. Source: (BP, 2006).

Similar to the oil industry in India, the Ministry of Coal has recently proposed setting up a new subsidiary within Coal India Limited (CIL) called Coal Videsh Limited, which is expected to acquire and operate mines outside the country and also import coal for domestic use.[129] Although this proposal is not yet approved, CIL has begun preparations for acquiring mines in Zimbabwe, Mozambique, Australia, Indonesia and South Africa.[130] Joint mining is also planned in many of these mines. Such international mine acquisitions are aimed at increasing India's energy security by producing and importing coal at reasonable prices.

[129] See: A. Mukherjee, "Coal Ministry to proceed with CIL's subsidiary plan", Business Line, June 13, 2006. http://www.blonnet.com/2006/06/13/stories/2006061303670300.htm

[130] See: S. Narayan and R. Jayaswal, "Coal India now digs the world for mines", Times of India, March 10, 2007. http://economictimes.indiatimes.com/articleshow/1744246.cms

3.3 Protecting the local environment

3.3.1 Background

The protection of environment became a serious policy issue in India only in the late 1960s and early 1970s (Khator, 1991).[131] Before this time, policies did not consider environmental protection as part of the development process, but it was taken up in a piece-meal fashion. For example, although there were laws on forests[132] prior to independence, it was more about protection of resources for a managed commercial exploitation, rather than protection of resources for the people (Khator, 1991). Government regulation of industries, factories, and mining immediately after independence included only health and safety aspects, without any reference to environmental protection directly.

Environment, as a policy issue, came to the forefront mainly because of India's participation in the 1972 United Nations Conference on the Human Environment (Dwivedi and Kishore, 1982; Khator, 1991; Divan and Rosencranz, 2001).[133] The Prime Minister of India, Mrs. Indira Gandhi, was particularly influenced by the UN environment conference,[134] and she pushed for the passage of a Water Act in 1974 and an Air Act on 1981 to prevent and control water and air pollution, respectively. The first environmental institution in India was the National Committee on Environmental Planning and Coordination (NCEPC), which was created as a result of the preparatory work undertaken for the 1972 UN conference. The NCEPC was to be an apex advisory body in all environment-related matters (Dwivedi and Kishore, 1982). In 1980, a Department of Environment was created as a nodal agency for environmental appraisal of development projects, protection and conservation of wildlife, monitoring and controlling water and air quality (under the Water and Air Acts), and coordinating the central and state actions. This department was converted to an independent ministry in 1985, and with the passage of the Environment (Protection) Act in 1986, the Ministry of Environment and Forests (MoEF) became fully institutionalized with several agencies and divisions under it (Khator, 1991).

Although India took up environmental protection quite seriously by passing laws and creating institutions, there was a key difference between India and other key industrialized countries. In the United States, for example, environmental laws and agencies were created because of rising public pressure to protect the environment – a public push which peaked at the 1970 Earth Day activities (Silveira, 2001). There was significant support by the general public and non-governmental organizations to ensure the successful implementation of the environmental agenda in the United States. On the other hand, environment policy in India was led by the

[131] There is general underlying belief that the broader Indian society respects and protects of natural resources, although it may not necessarily be reflected in its behavior and actions (Khator, 1991).
[132] The focus of the British-India legislation was mainly on creating a bureaucratic regulation of forests and other resources (Khator, 1991).
[133] The United Nations Conference on the Human Environment was initiated to create an international action plan on protecting the environment and to include environmental concerns in development. http://www.unep.org/Documents.multilingual/Default.asp?DocumentID=97.
[134] As Khator (1991) notes, Mrs. Gandhi was influenced by the UN conference and "Mrs. Gandhi's personal commitment toward environmental protection" was the "single most important factor brought the environmental movement to the Indian door".

government without any direct support from the broader public or electoral mandate.[135] Rather, the issue was defined by the government, based on perceptions of people within the government, and the chosen bureaucratic strategies were those that were preferred by the government (Khator, 1991). Although laws were passed, there was (and still is) little emphasis on enforcement, and the environmental agenda in the country fail to withstand pressure from other ministries and interest groups, particularly the industry.[136] In fact, much of the enforcement of environmental regulations in India has come about because of judicial interventions.

The MoEF is also the nodal agency for climate change and, in principle, this has the benefit of promoting an alignment between climate and other environmental policies (which is important for developing technology policies regarding carbon capture and storage), but on the other hand, given the relatively weak influence yielded by Ministry, the climate issue often gets superseded by what are seen as more immediate and pressing concerns. MoEF is often overextended by the large range of issues it has to deal with in environment and forestry issues in India, reducing the amount of attention that can be devoted to the development of better policies for the coal power sector.

It is in this context that one must consider the impacts of coal-based generation on local environment and its mitigation.

3.3.2 Impact of coal-power generation

Coal-based power plants significantly impact the local environment. Direct impacts resulting from construction and ongoing operations include:

- flue gas emissions – particulates, sulfur oxides, nitrous oxides, and other hazardous chemicals
- pollution of local water streams, rivers and ground water from effluent discharges and percolation of hazardous materials from the stored flyash
- degradation of land used for storing flyash
- noise pollution during operation

The indirect impacts result mainly from coal mining, which includes degradation and destruction of land, water, forests, habitats, and societies. In addition to the impact of the coal-power plants, there is also the much larger issue of the environmental and social impact of coal mining. Although this is very important and crucial challenge for the coal and coal-power sectors, this issue is not discussed in detail here; please see Chikkatur et al. (2007b), and references therein, for a review and discussion of this issue.

Currently, more than 80 large (> 100 MW) coal-based power stations operate in the country, with electricity production increasing from 2.4 TWh in 1950 to 420 TWh in 2004. As a consequence of this large scale infrastructure development, the environmental and social impacts

[135] Although Dwivedi and Kishore (1982) note that all political parties in the 1980 elections had something to say about environment in their platforms, environment was not a decisive political issue at that time. Also, there has been considerable local public involvement and support for environmental protection and strong (and successful) protests against specific local projects (for example, the Chipko Andolan, the Narmada Bachao Andolan, the Samata protests, Cogentrix protests, etc.). While many of these protests have been successful locally (in stopping local projects), they have not led to significant changes in environmental enforcement or bureaucracy.

[136] See, for example, Khator (1991) and Sunita Dubey (2006), "An Undemocratic Environment" http://indiatogether.org/2006/oct/env-democenv.htm.

of Indian coal-based plants have been significant (as we shall briefly discuss in the following sub-sections). As the installed capacity and electricity generation will increase in the future (see section 3.1), so will these impacts, unless there is a concerted effort to reduce environmental and social damages.

The broad impacts on environment and human health imply that the government must regulate various aspects of power plant operations and construction to reduce their environmental and social impacts. The primary responsibility for creating and enforcing environmental regulations lies with the state and central pollution control boards, which are under the state and central ministries of environment and forests, respectively. For large thermal power plants, the central Ministry of Environment and Forests (MoEF) has to give an environmental clearance, based on the environmental impact assessment (EIA) for project, before it can be approved for construction.[137] The EIA and subsequent public hearing process is expected to allow for the consideration of the environmental issues and take input from local communities; however, analysts have pointed out that the EIA process has been subverted in many cases.[138]

Even the enforcement of regulations has been lax, and the emphasis has mainly been on particulate emissions. Assessments of environmental impacts and routine monitoring are expected of all power stations, yet there is little penalty for violating the norms. Although there are provisions in the law that allow for closing down power plants for not meeting environmental standards, the plants are not closed down because India "can hardly afford to close any unit in the power starved situation" (CEA, 2004b, 2005b). The Central Pollution Control Board (CPCB) has noted that many thermal power plants default on meeting pollution standards. As Table 10 shows, about 30% of thermal power plants continue to fail to meet the expected standards for emissions and about 20% fail to meet effluent standards.[139]

Year	Total Number of Operating Plants	Emission Standard		Effluent Standard	
		Comply	Not Comply	Comply	Not Comply
1999-00	74	34	40		
2000-01	76	48	28		
2001-02	78	42	36	49	29
2002-03	79	48	31	52	27
2003-04	78	56	22	63	15
2004-05	78	55	23	63	15
2005-06	78	56	22	63	15
2006-07	78	56	22	63	15

Table 10: Compliance of standards for Coal-Based Thermal Power plants.
Source: CPCB Annual Report, various years

With the projected increase in installed capacity, a key challenge for the government is to effectively enforce and tighten its existing regulations and add additional regulations as deemed

[137] See: Environment Impact Assessment Notification S.O.60(E); http://envfor.nic.in/legis/eia/so-60(e).html.
[138] For example, see: Sunita Dubey, "EIA: Foundations of Failure" (2006), http://www.indiatogether.org/2006/mar/env-eiafail.htm and Sunita Dubey, "Weakening the enviro-clearance process" (2004), http://www.indiatogether.org/2004/aug/env-eiaweakn.htm.
[139] The current situation is considerably better than in the mid-80s. For example, in 1984, 31 out of 48 thermal power plants surveyed had no pollution control technology (Khator, 1991).

appropriate to protect local environment and ecologies. In 2003, the MoEF and CPCB initiated a process for developing the Charter on the Corporate Responsibility for Environmental Protection (CREP).[140] The aim of CREP was to work with various industries and get them to install cleaner technologies and commit themselves to better regulatory norms for prevention and control of pollution. With regard to thermal power plants, the CREP aimed to get non-compliant plants to install pollution control equipment, establish tighter pollution standards, get power plants to use beneficiated coal, fully utilize flyash, and promote the use of new cleaner coal technologies.[141] New technologies, if chosen correctly, can help meet this challenge of environmental protection along with growth in new capacity.

In the following sections, the environmental hazards of coal-based power plants will be briefly discussed, along with possibilities for decreasing the environmental impacts in the future.

3.3.3 Air pollution

A thermal power plant emits many pollutants into the air – dust from the coal handling area, fugitive dust from ash ponds, fly-ash and fine particulate emissions, flue gas emission of sulfur and nitrogen oxides, mercury, volatile organic compounds, etc.[142] Generally, particulate matter, sulfur oxides, and nitrogen oxides are considered as 'criteria' air pollutants and there is an enormous focus worldwide on reducing emission of these air pollutants.[143] In this section, we primarily focus on these three criteria pollutants and only very briefly describe the problems of other pollutants such as mercury and volatile organic compounds. Table 11 shows the pollutant levels from a typical 210 MW unit in India.

Coal	130 ton / hr
Air	700 ton / hr
Volume of flue gas	800 ton/ hr or 410-430 m3/sec
Temperature	140-170 °C
Excess oxygen	3-4%
CO2	13 - 15 %
Moisture	4-5%
SOx	700-1200 mg/Nm^3
NOx	300-500 mg/Nm^3
Fly ash	65000 mg/Nm^3 (before ESP)
	~120 mg/ Nm^3 (after ESP)

Table 11: Typical operating parameters of a 210 MW unit in India. Source: (Sonde, 2005).

Given the significant emissions of criteria pollutants in the aggregate, the government has mandated limits on these emissions. However, emission limits from the power plant stack are defined only for particulates, but not for sulfur or nitrogen oxides—for these emissions, only the national ambient air quality standards (NAAQS; see Table 12) apply. The NAAQS are divided into area-specific standards (industrial areas, residential/rural/other areas, and sensitive areas).

[140] See: http://www.cpcb.nic.in/oldwebsite/Charter/charter.htm
[141] For the latest status on CREP implementation, see: http://www.cpcb.nic.in/oldwebsite/Charter/status.htm.
[142] Flue gas also contains carbon-dioxide (CO_2), which is not yet considered as a pollutant. Its emissions might be regulated in the future because of its role in global warming and climate change. The issue of CO_2 emissions is discussed later in section 3.4.
[143] Other criteria pollutants include lead, carbon monoxide and ozone, which are usually emitted by mobile sources (vehicles). See: http://www.epa.gov/air/urbanair/6poll.html.

Typically, the standards are weaker for the industrial areas when compared to residential and sensitive areas.

Pollutants	Time-weighted average	Concentration in ambient air		
		Industrial Areas	Residential, Rural & other Areas	Sensitive Areas
Sulfur Dioxide (SO_2)	Annual Average*	80 µg/m^3	60 µg/m^3	15 µg/m^3
	24 hours**	120 µg/m^3	80 µg/m^3	30 µg/m^3
Oxides of Nitrogen (NO_x)	Annual Average*	80 µg/m^3	60 µg/m^3	15 µg/m^3
	24 hours**	120 µg/m^3	80 µg/m^3	30 µg/m^3
Suspended Particulate Matter (SPM)	Annual Average*	360 µg/m^3	140 µg/m^3	70 µg/m^3
	24 hours**	500 µg/m^3	200 µg/m^3	100 µg/m^3
Respirable Particulate Matter (RPM) (size < 10 µm)	Annual Average*	120 µg/m^3	60 µg/m^3	50 µg/m^3
	24 hours**	150 µg/m^3	100 µg/m^3	75 µg/m^3
*	Annual Arithmetic mean of minimum 104 measurements in a year taken twice a week 24 hourly at uniform interval.			
**	24 hourly/8 hourly values should be met 98% of the time in a year. However, 2% of the time, it may exceed but not on two consecutive days.			

Table 12: Current National Ambient Air Quality Standards. Source: CPCB website (accessed December 2007)

Recently, the CPCB drafted new NAAQS which are stronger than the current standards and moreover has defined standards for more air pollutants, including volatile organic compounds (such as benzene and formaldehyde), lead, mercury, nickel, vanadium, and particulate matter less than 10 µm (PM10) and 2.5 µm (PM2.5).[144] The new draft standard also has eliminated area-specific standards, and only provides stronger standards for sulfur and nitrogen oxide emissions in sensitive areas.

3.3.3.1 Particulate Emission

Most of the particulate emissions come from the flue gas, although fugitive dust from coal and handling plants and dried-up ash ponds are also significant sources of particulate pollution. Particulate matter much larger than 10 microns is mostly captured by the electrostatic precipitators of power plants. However, smaller particles (less than 10 microns (PM10)) are considered as particularly dangerous for human health and environment. Some of the main health and environmental hazards of particulate matter include[145]:

- Increase in respiratory problems such as aggravation of asthma, increase in coughing and difficult breathing, chronic bronchitis, decreased lung function, and premature death
- Reduction in visibility in areas surrounding emission sources such as power plants, urban areas, etc.

[144] See: http://www.cpcb.nic.in/draftstandards.doc (accessed March 2008).
[145] U.S. Environment Protection Agency (USEPA) website, “Six Common Air Pollutants”; http://www.epa.gov/air/urbanair/6poll.html

- Deposition and settling of particulate matter on lakes, streams, soil, etc. – leading to changes in soil and water nutrient balance, damaging forests and farms, and affecting regional ecosystem diversity.

Particulate emissions are regulated more rigorously than other pollutants in India. Prior to the 1970s, most power plants had mechanical dust collectors (MDCs), electrostatic precipitators (ESPs) or a combination of MDC and ESP. Much of these control devices did not have significant impact on reducing emissions (Bhattacharyya, 1997). The control devices were gross inadequate to deal with Indian ash, which tends to be smaller in size and with high resistivity (Subramanian, 1997). In 1984, regulations in India have placed an emission limit on suspended particulate emissions from coal-based power plants, although the limit does not differentiate between particulate sizes, unlike in the United States and Europe. These regulations ensured the complete replacement and/or refurbishment of many of the non-performing ESPs, so that power plants could meet the required limits. The emission limits have also been tightening over time, and they are expected to become even tighter if the CREP recommendations are adopted (see Table 13). In fact, new power plants in the country are being asked to follow the CREP proposed limit of 100 mg/Nm^3.[146]

Although particulate emission requirement is more stringent than emission of other pollutants, 22 power stations out of 78 did not meet the particulate emission constraint in 2006-07 (see Table 10). The CEA, CPCB, and the power plants do, however, extend enormous efforts to reduce flue gas particulate emissions, and the control equipment of many power plants have been augmented over the years to meet the required limits. However, it is to be noted that the focus on emission control from power plants is primarily on PM10 and not on PM2.5, despite the fact that PM2.5 is very hazardous since these fine particles can penetrate and lodge deeper into our lungs.[147] In fact, it is only recently that the draft ambient air quality standards have defined limits for PM2.5.

Year	Emission Limit[148] mg/Nm^3	Conditions
1984	150/350/600	Based on unit size, location, and age of plant
1993	150	All power plants greater than 62.5 MW and for those in protected areas
1993	350	Power plants less than 62.5 MW that are not in protected areas
2003	100	CREP standards (to be implemented)

Table 13: Regulatory History of Particulate Emissions from power plants in India.
Source: (Visuvasam et al., 2005).

Typically, the poorest quality of thermal coal (grades E to G) is supplied to power plants(Ministry of Coal, 2005a), and the high ash content (40-50%) of Indian coals naturally

[146] See: http://www.cpcb.nic.in/oldwebsite/Charter/status.htm
[147] PM2.5 emissions are currently being regulated in U.S., Canada, Thailand, and Australia (see: http://www.cpcb.nic.in/draftstandards.doc).
[148] The unit 'mg/Nm^3' means milligrams of particulates per normal cubic meter of air, at standard pressure and temperature.

leads to high concentration of particulates in the flue gas, which has to then be extracted by precipitators. In a 210 MW plant, the density of particles in untreated flue gas is about 65 g/Nm^3 (see Table 11), which is then reduced to the low value of 150 mg/Nm^3 using ESPs (see Box 1). In spite of using ESPs, the total emission of particulate matter from power plants is quite high in India. It was estimated that the total PM10 emissions in India (excluding biomass combustion and secondary nitrates) in 1990 was about 12.5 Tg/year,[149] in comparison to 22 Tg/year and 46.5 Tg/year for U.S. and China, respectively (Wolf and Hidy, 1997). Furthermore, recent work indicates that in the downwind areas near power plants have higher PM10 concentrations in ambient air than the prescribed CPCB standards (R. Sharma et al., 2005). Furthermore, the winter and summer months show higher PM concentration than the post-rainy reason.

In terms of PM2.5, there has been very little work focused specifically on areas near power plants, as most of the effort has been in urban areas. Reddy and Venkataraman (2000) have estimated that in 1990, carbonaceous PM2.5 emissions[150] in the country were about 5.7 Tg/year, out of which the contribution of coal-based power generation was 2.3 Tg/year. They have updated their estimates for the PM2.5 emissions to be between 0.5 and 2.0 Tg/year in 1996-97, with the lower and higher values representing 100% and 50% control of emissions from installed pollution control devices such as precipitators in power plants. It is estimated that if the pollution control devices installed on power plants are operated at maximum efficiency (100% control), then about 97% of the PM2.5 emissions can be removed (Reddy and Venkataraman, 2002).

Based on morbidity resulting from respiratory problems and loss of rent from building damages, one can estimate a monetary value on the environmental cost of particulate emissions. A calculation of this kind by Bhattacharyya (1997) indicated that the cost of particulate emissions in India was about Rs. 0.054 per kWh (Rs. 275/kg; $3.8/lb) for a base-load use of a 210 MW coal power plant.[151] This cost is more than three times higher than the starting point cost ($1.18/lb of particulate emissions) for U.S. power plants, based on mortality, morbidity and visibility effects of particulate emissions (Ottinger et al., 1990).[152]

Box 1: Electrostatic precipitators

The main technology in India for particulate extraction from flue gas of coal combustion processes is the cold-side electrostatic precipitator (ESP) with design efficiencies greater than 99% (Gyllenspetz et al., 1998), although other devices such as mechanical collectors and dust collectors are in place for some older units installed in the 60s.[153] The high ash content of Indian coal naturally leads to high particulate content and high temperature of the flue gas. The dust load into the precipitators is about 6 times larger than U.S. plants using Ohio coals and 12 times larger than in China (Visuvasam et al., 2005).

[149] Tg = Teragram = 10^{12} grams
[150] PM2.5 emissions include inorganic flyash, as well as black carbon and other organic matter.
[151] This cost is specific to the 210 MW plant and the particular assumptions used in the study. The cost could vary considerably if atmospheric conditions and other assumptions are altered. The calculations also assume an exchange rate of about Rs. 32/USD (Bhattacharyya, 1997).
[152] Ottinger et al. (1990) costs are based on 1989 dollars.
[153] In 1997, 73% of power plants used ESP, 22% used ESP in combination with other devices (mechanical collectors, bagfilters, etc.), and 3% using multiple cyclones (Reddy and Venkataraman, 2002). The addition of MDC with ESP, in fact, reduced the overall efficiency of devices, and the use of only ESPs was better (Subramanian, 1997).

In addition, the low sulfur and sodium content combined with the high silica and alumina content leads to high ash resistivity, which reduces the ESP's efficiency and increase emissions by reverse ionization.[154] Therefore, it is essential to increase the size of the precipitator collection area to around 200 m^2/m^3/hr,[155] increase residence time to about 30 s, design effective electrical control of ESP, control the frequency and intensity of rapping,[156] and frequently remove ash from the hoppers (Subramanian, 1997; Gyllenspetz et al., 1998). BHEL has done some R&D on improving ESP performance (Subramanian, 1997). Many of the ESPs had to be augmented after the 1984 regulations were put in place, since the units simply did not have enough capacity to handle the high particulate content in the flue gas.[157]

Given these inherent difficulties of capturing fly ash from flue gases in India, an important challenge for power plants, as regulations are tightened, is to continue to reduce their particulate emissions. The efficiency of the existing ESPs will have to be furthered increased and additional ESPs might have to be added. Properties of the flue gas might need to be altered to reduce resistivity and improve collection by the ESP. NTPC, supported by USAID, has been doing much of the research in improving ESP performance by conditioning the flue gas with moisture to increase ESP performance and injecting sodium salts in the boiler to reduce flue gas resistivity and particulate loading (NTPC, 1999; U.S. DOE, 1999).[158]

3.3.3.2 Sulfur oxides

The sulfur in coal reacts with oxygen during combustion to form sulfur oxides (SO_x), of which about 97% is sulfur dioxide (SO_2), with the rest being SO_3. SO_2 is converted to sulfuric acid in the presence of water vapor in the atmosphere; sulfuric acid has a deleterious effect on animals and plants (CEA, 2004b). Some of the impacts of sulfur oxides on human health and environment include:[159]

- Respiratory impacts such as breathing difficulty, aggravation of heart diseases, and acceleration of respiratory illness from longer-term exposure.
- The formation of sulfate particles that collect in lungs and increase respiratory symptoms, resulting in premature deaths.
- The formation of haze due to sulfate particles, which impairs visibility.
- SO_2 and nitrogen oxides react with other substances in the air to form acids, which fall back to earth as rain, fog, snow, or dry particles. Acid rain damages human habitations, forests, crops, fisheries, and water bodies – altering regional ecosystems.

SO_x emission from power plants is generally considered to be less of an issue in India, since most Indian coals have low sulfur content. Coal supplied to Indian power plants has sulfur content ranging from 0.1 to 0.8%, with a consumption-weighted average of 0.59% (Reddy and

---

[154] Interestingly, the ESPs were ordered in the 60s without first measuring the resistivity of the ash. It was only much later that the ash properties were measured in a Swedish lab (Subramanian, 1997).
[155] For example, the specific plate area of an ESP in 1979 was only about 120 m^2/m^3/hr (Subramanian, 1997).
[156] The dust collected on the collectors is removed by mechanical rapping. The dust is then gathered into hoppers, from which ash is removed dry or as slurry.
[157] Interview with MSEB official (February 2005).
[158] For example, injection of 0.25% by weight of sodium to coal in a 67 MW Korba power plant unit reduced the particulate content in the flue gas by more than 80% (U.S. DOE, 1999).
[159] U.S. Environment Protection Agency (USEPA) website, "Six Common Air Pollutants"; http://www.epa.gov/air/urbanair/6poll.html

Venkataraman, 2002).[160] Therefore, all of the Indian power plants, except for one,[161] have no SO_x emission control technologies. In comparison, the average sulfur content of coals consumed by U.S. power plants is about 1.1% (EIA, 2000).[162] Garg and collaborators have estimated that during 1990-1995, about 7 tons of SO_2 was emitted for every GWh generated by Indian power plants (Garg et al., 2001b). They have estimated all-India SO_2 emissions to be 3.54 Tg in 1990 and 4.64 Tg in 1995, of which 46% was from power plants. More recent estimates by Reddy and Venkataraman (2002) have pegged the SO_2 emissions by utility power plants in 1996-97 to be 2 Tg, with more than 75% contribution from coal combustion and the rest by fuel oil.

Box 2: Flue Gas Desulfurization (FGD) plants

Although there is no current requirement for having additional desulfurization equipment for removing SO2 from flue gases, the MoEF does stipulate that space for FGD installation be set aside in power plants with 500 MW (and greater) units and for power stations with total installed capacity of 1500-2000 MW. This space will help facilitate retrofitting of FGDs, if at a later stage stringent norms are specified. In sensitive areas[163], the installation of FGD is insisted upon even for stations with smaller installation (CEA, 2004b).

Currently, only one power plant in India owned by Tata Power Corporation has installed a seawater-based FGD – the 500 MW Trombay TPS (TTPS) unit 5. The FGD is an Alstom unit with 90% removal efficiency, and it was installed in 1988 at a cost of Rs. 100 cores.[164] The FGD was installed as the power plant is close to the densely populated Mumbai city. Similarly, in 2000, the Supreme Court of India ordered Reliance Energy Limited to install FGD for its 500 MW (2 x 250 MW) Dahanu TPS (DTPS), since the power plant is located in an ecologically sensitive area. As of now, the Dahanu FGD is expected to be commissioned by August 2007.[165]

Current regulation of SO_2 in power plants in India is only concerned with reducing its concentration by dispersal and dilution. Rather than limiting the quantity of SO_2 emissions in the flue gas, the height of the flue gas stack is regulated – height increases as the power plant size increases. However, these heights might not be enough to reach above the inversion layer in North India (Subramanian, 1997). Although stack SO_2 emissions are not limited or monitored, power plants do have to meet the ambient air quality standards (see Table 12). Most of the power plants seem to meet the ambient standards, although some of the highly industrialized areas with coal mining and thermal power plants, such as Dhanbad, Jharia, Anpara, Chandrapur, etc., have high concentrations of SO_2, and sometimes the ambient air quality limits are violated (CPCB, 2000a, 2001).

---

[160] Garg *et al.* (2001b) have claimed a weighted average of 0.51% for sulfur in Indian coals.

[161] The Trombay Thermal Power Station near Mumbai has a sea-water based FGD.

[162] In 1997, the average sulfur content in coal received by U.S. electric utilities is 1.09 pounds/million BTU, and the average BTU content of coal is 10,266 BTU per pound of coal (EIA, 2000).

[163] Sensitive areas include large urban areas, reserved and protected forest land, coastal regulation zones, nature reserves, parks and special protection areas as specified by MoEF (NEERI, 2003).

[164] Sanjay Jog, "REL Takes Tata Power's Advice to Install FGD Plant" Financial Express, April 24, 2004. http://www.financialexpress.com/fe_full_story.php?content_id=57731

[165] "REL ropes in US firm for Dahanu operations" The Economic Times, March 29, 2005. http://economictimes.indiatimes.com/articleshow/msid-1064504,curpg-1.cms

Environmental costs of SO_2 emissions in India can be estimated mainly from mortality and morbidity effects. Bhattacharyya's (1997) calculation indicates this cost to be about Rs. 0.335/kWh (Rs. 133/kg; $1.86/lb) for SO_2 emissions from a 210 MW power plant.[151] In contrast to the high cost of particulate emissions, the environmental cost of sulfur emissions in India is comparable to cost estimates in U.S. power plants because of the low sulfur content in Indian coals (in spite of using more coal to generate a unit of electricity).[166]

It is possible that sulfur emissions from power plants will eventually be controlled, similar to the particulates. When such regulations are in place, an important challenge will be to ensure that power plants reduce their SO_2 emissions, and to routinely monitor these emissions and to ensure that power plants install (or retrofit) flue gas desulfurization (FGD) plants (see Box 2), as required, to reduce SO_2 emissions. An additional factor that might require the use of in-plant control technologies to manage sulfur emissions is that Indian coals do not appear to benefit from coal washing. The sulfur in Indian coal is mostly in organic form and chemically bound to the coal matrix; hence, it cannot be removed by physical cleaning methods (Lookman and Rubin, 1998).

3.3.3.3 Nitrogen Oxides

Nitrogen at high temperatures reacts with oxygen in the air to form nitrogen oxides (NO_x); the rate of NO_x production increases with temperature. In PC plants, NO_x is formed in the boiler due to the high temperatures that result from coal combustion. The main concerns and problems with NO_x emissions include[167]:

- The formation of ground-level ozone and smog from interactions of NO_x and volatile organic compounds in the presence of sunlight. The ozone and smog can trigger serious respiratory problems and damage lung tissue. Ozone can be transported long distances by wind and can impact areas far from its source;
- The formation nitrate particles, acid aerosols, and other compounds which also cause respiratory problems, including effects on breathing and the respiratory system, damage to lung tissue, and premature death;
- The formation of acid rain as NO_x and sulfur dioxide react with air to form acids that fall back to Earth as rain, fog, snow, or dry particles. As discussed earlier, acid rain strongly affects regional ecosystems;
- The deterioration of water quality by nutrient overloading in water bodies; and
- The formation of atmospheric particles that impair visibility.

NO_x emissions are not currently regulated in India for coal-based power plants,[168] although there are NO_x emission limits for ambient air (Table 12). About 30% of NO_x emissions in India derive from power generation, another 30% from transportation, 20% each for industry and biomass burning (Garg et al., 2001b). While there is a close relationship between coal and oil

[166] Ottinger et al. (1990) estimates a starting point cost of $2.03/lb of SO_2 emissions based on mortality, morbidity, material corrosion, and visibility effects.
[167] U.S. Environment Protection Agency (USEPA) website, "Six Common Air Pollutants"; http://www.epa.gov/air/urbanair/6poll.html
[168] On the other hand, gas-based power plants have an emission limit that varies between 50-150 ppm, depending on the age and size of the gas turbines (CPCB, 2005).

consumption with regional NO_x emission, emissions from transportation is the key culprit in urban areas.

Key technologies for reducing NO_x emissions in power plant include low-NO_x burners, ammonia injection in flue gas streams, and selective catalytic reducer (SCR). Currently, many of the boilers are designed with NO_x production limit of 260 g/GJ, and furnace temperatures can be reduced by over-fire air dampers (NTPC, 2004). India has developed its own SCR technology using injection of titania catalysts, and a pilot scale technology demonstration was successfully completed at NTPC's Badarpur thermal power plant in 1988-89 (CPCB, 2000b). Deployment of this technology has been held by lack of statutory standards for NO_x emissions. Emission standards for coal power plants were expected to come out of the CPCB's CREP charter by December 2003, although the current status of CREP standards is unclear.[169]

3.3.3.4 Mercury Emissions

A growing concern in India is the release of trace elements such as mercury (Hg), arsenic (As), lead (Pb), cadmium (Cd), etc., from power plants through the disposal and dispersal of coal ash. The concentrations of many trace elements are high in comparison to coals from other countries (see Table 14). For more details, see Masto et al. (2007).

Element	Earth's Crust Average	Indian Minimum	Indian Maximum	Indian Average	British Average	US Average	Australian Average	Worldwide Average
As	2.0	0.1	23.0	5.0	18	15	3	5
Hg	0.1	0.0	2.7	0.35	--	0.18	0.1	0.012
Cd	0.15	0.0	13.0	1.3	0.4	1.3	0.1	-
Pb	16.0	0.0	46.5	15.0	38	16	10	25
Cr	200.0	5.0	90.8	70.0	33.6	15	6	10
Ni	80.0	0.0	100.0	45.0	27.9	15	15	15
Co	23.0	2.1	40.0	11.0	--	7	-	5

Table 14: Concentration (mg/kg) of trace elements in Indian coal and lignite, compared to Earth's crust and other coals. Source: (Masto et al., 2007).

Mercury emissions are of particular concern, as exposure to mercury at high levels can harm the brain, heart, kidneys, lungs, and immune system of people of all ages.[170] Mercury present in flue gases and in flyash/bottom-ash that is disposed off in ash ponds enters the hydrological system, wherein the mercury is methlyated in oceans and rivers; methyl-mercury can then enter the human food chain, mainly through consumption of fish (Shah et al., 2008). Mercury can be emitted in three different forms: elemental (Hg^0), oxidized (Hg^{2+}) and particle bound (Hg^P). Most of the mercury from coal combustion is released as Hg^0, which has longer lifetime in the environment, compared to Hg^P and Hg^{2+}, which are more soluble. Furthermore, Hg^P and Hg^{2+} are also easier to capture by conventional pollution control technologies compared to Hg^0 (Shah et al., 2008).

[169] In September 2005, a committee formed to address this issue recommended to get more reliable data on NO_x emissions before suggesting draft standards. See: http://cpcb.nic.in//Charter/status.htm.
[170] http://www.epa.gov/mercury/about.htm

Estimates of mercury in Indian coal vary significantly as coals from different coalfields have a wide range of mercury concentration. Coals from East Bokaro, West Bokaro, South Karanpura, Auranga, Wardha Valley, and West Bengal lignite fields have particularly high amounts of mercury (Masto et al., 2007).[171] Average concentration of mercury in coal is estimated to be 0.35 mg/kg in Masto et al. (2007) and 0.38 mg/kg in Mukherjee and Zevenhoven (2006). Upon combustion, coal flyash tends to have a higher concentration of mercury, and estimates indicate that Indian coal ash has an average mercury concentration of 0.53 mg/kg, based on measurements from a few selected power plants (Mukherjee and Zevenhoven, 2006). A small experiment at an NTPC 500 MW power plant indicated that the concentration of mercury in the stack flue gas was about 2.8 +/- 0.5 $\mu g/m^3$ (Jain and Roy, 1999). About 41 tons of mercury was estimated to be released in the 78 MT of coal flyash in 1997-98, with the majority being in the Western Region (Mukherjee and Zevenhoven, 2006). It is projected that mercury in coal flyash will nearly double to about 80 tons by 2012.

Control of mercury emissions from coal-fired power plants is becoming an important issue globally, although India has not yet responded to the call. Currently, there is no NAAQS for mercury, although there are standards set for emissions and effluents for various industrial processes—although there are no limits set for mercury emissions from power plants, there are some general limits for mercury in power plant effluents.

There are several different options for reducing mercury emissions from power plants (Yudovich and Ketris, 2005):[172]

- Selective mining of low-mercury coals,[173]
- Coal washing/beneficiation – this depends on coal characteristics, but about 30-80% of mercury can be reduced by proper washing,
- Fluidized bed combustion, especially for high chlorine coals,
- Use of pollution control devices such as low-NOx burners, cold-side ESPs, bag-filters, FGD, and SCR, and
- Sorbent injection into flue gas ducts – typically, activated carbon can be injected either upstream or downstream of the ESP.

Control of mercury emissions has so far not been on the forefront of pollution reduction from coal power plants in India, however, greater use of washed coals and pollution control devices in India would already help in reducing mercury emissions.

3.3.4 Water pollution

Water is extensively used in thermal power plants as coolant for the thermal cycle.[174] Although there is little or no chemical contamination of this cooling water, the introduction of waste heat

---

[171] This is based on the high minimum value (>0.2 mg/kg) of mercury.
[172] For more details, see (Yudovich and Ketris, 2005).
[173] Selective mining could be a viable and relatively cheap option to reduce mercury content of Indian coals, especially since Indian coalfields have a wide range of mercury concentrations (Masto et al., 2007). However, proper characterization of coal seams is critical for selective mining.
[174] Even greater amount of water is needed if the power plants are using once-thru cooling systems, where the water for cooling is used only once rather than being recycled and air-cooled in cooling towers.

into rivers and local streams can strongly affect aquatic plants and animals. There is regulation for the maximum increase in cooling water temperature,[175] although it is not clear as to how strictly the regulation is enforced. However, all power plants that use water from lakes, rivers and reservoirs are mandated to have air-based cooling towers regardless of its capacity (CPCB, 2005). Suction of large amounts of water for cooling can also kill fish and shellfish, and reduce their population, as the fish impinge on the suction systems (NEERI 2003). In addition to thermal pollution, effluents (such as waste water effluents are generated from demineralizer backwash, resin regenerator, boiler blow down, ash transport, runoff from coal and ash piles) and discharges from accidents and spills from thermal power plants can pollute local water bodies, including ground water (NEERI 2003).

In addition to being used as a coolant, a large volume of water is also consumed for making ash slurry – the water requirement is about five times the amount of ash. The water used for the fly-ash slurry is generally not recycled, increasing both the consumption of water and generation of wastewater effluents. The wastewater from the ash pond can contaminate local streams, rivers and can also leach hazardous chemicals into the ground water. MoEF has mandated that ash ponds and coal-yards must have an impervious lining in order to reduce leaching, although coal-ash from power plants is generally not regarded as hazardous waste (Balachandra and Sharma, 2001), especially since the use of ash in bricks and cement is being encouraged.

In many areas, the ash-pond effluent is used for irrigation and for drinking, as untainted, clean local water sources has become scarce. Use of this water as potable water and as irrigation water can lead to direct and indirect consumption of heavy metals and other toxins that are present in flyash. Both humans and livestock can be adversely affected, as the ash-pond effluent often "does not meet Indian standards for total suspended solids (TSS)[176] due to poor management of the ash-pond for settling" (NEERI 2003).

3.3.5 Land use and impact on communities

It is claimed that forest land[177] is generally not used for building thermal power plants and hence the issues related with conversion of forest land into non-forest use would likely be minimal (CEA, 2004b). However, the construction of power plants also adversely impacts the land and local environment – possible impacts include site preparation activities such as clearing, excavation, de-watering, dredging, impounding streams and other water bodies, etc. (NEERI, 2003).

The people who are directly affected by a coal power project include those who will be displaced from their lands and have to be rehabilitated elsewhere, and those who's health and agriculture will be affected most directly by local air and water pollution emanating from coal power plants.

---

[175] For thermal power plants existing before June, 1999, the maximum change in cooling water temperature between the inlet and the outlet of the condenser is $10^{o}C$; for sea-water based power plants built after June 1999, the maximum change in temperature is $7^{o}C$ (CPCB, 2005).

[176] MoEF stipulates that the ash pond and boiler blow-down effluents from thermal power plants should not have suspended solids greater than 100 grams/milliliter (CPCB, 2005).

[177] 'Forest' land is a legal category, whereby the land is managed and ostensibly protected by the Department of Forests, which is now under the Ministry of Environment and Forests. Converting 'forest' land into non-forest land requires the permission of the Forest Department. For pithead plants, the land may have de-notified earlier for mining.

Usually, communities on or near a power plant location will have to be resettled elsewhere, albeit the problems of resettlement and rehabilitation are not as widespread as for irrigation, hydroelectricity and mining projects. Power plant construction also involves a large influx of laborers. Several thousand laborers may be required during the minimum three year construction period; the workers may displace local communities and strain the existing infrastructure such as hospitals, schools, police, fire protection, etc. Local culture and social values might be severely disrupted, as communities become submerged under this population influx (NEERI, 2003).

In addition, local communities are affected by the noise of operating power plants. A large amount of noise is generated by the coal handling plant, belt conveyors, pulverizers, boiler, turbines, fans, and other heavy machinery. The Ministry of Environment and Forests does regulate noise pollution and silencers are expected to be put on fans, compressors, etc., with noise absorption materials to be installed in much of the noisy areas. However, it is unclear as to how effectively these regulations are enforced.

3.4 Carbon dioxide, Climate Change and Developing Countries

In recent years, climate change has received significant and increasing attention, in terms of, both its possible impacts on humans, ecosystems, and economies, and the scale of efforts that will be needed to tackle and mitigate this problem. Climate change is driven by the accumulation in the atmosphere of heat trapping ("greenhouse") gases (GHG) resulting from anthropogenic activities -- carbon dioxide (CO_2), mostly the product of the combustion of fossil fuels for energy use, is the single largest contributor to the problem, accounting for about 60% of the direct radiative forcing of all greenhouse gases. Thus, the climate issue is intimately linked to the use of fossil fuels in the energy sector.

The most recent data indicates that CO_2 levels in the atmosphere now exceed 380 part per million by volume (ppmv), a significant rise from the pre-industrial concentration of about 280 ppmv (and other greenhouse gases have also shown significant rise in atmospheric concentrations). Manifestations of a warming planet and changing climate have become more apparent, such as a rise in the global mean surface temperatures—recent years being among the hottest on record, reductions in snow cover and ice in the northern latitudes and higher altitudes, melting of glaciers, and changes in precipitation patterns. Scenarios developed by the Intergovernmental Panel on Climate Change (IPCC) indicate that in the absence of targeted climate policies, the global mean surface temperatures will increase by 1.1 to 6.4^{o}C over the 21st century, accompanied by model-based estimates of sea-level rise of 0.18 to 0.59 meters (IPCC, 2007).

Regional-scale changes include:

- warming greatest over land and at most high northern latitudes and least over Southern Ocean and parts of the North Atlantic Ocean, continuing recent observed trends (Figure SPM.6) in contraction of snow cover area, increases in thaw depth over most permafrost regions, and decrease in sea ice extent; in some projections using SRES scenarios, Arctic late-summer sea ice disappears almost entirely by the latter part of the 21st century
- very likely increase in frequency of hot extremes, heat waves, and heavy precipitation
- likely increase in tropical cyclone intensity; less confidence in global decrease of tropical cyclone numbers
- poleward shift of extra-tropical storm tracks with consequent changes in wind, precipitation, and
- temperature patterns
- very likely precipitation increases in high latitudes and likely decreases in most subtropical land regions, continuing observed recent trends

.

Such changes in the climate could have enormous human, ecological, and economic impacts. For example, more intense rainfall could lead to floods and landslides and also contribute to greater erosion. Rise in mean temperatures could change disease patterns and affect agricultural productivity. More frequent and intense coastal storms could cause enormous damage to human settlements, coastal ecosystems, and result in loss of life.

Developing countries are at particular risk from climate change. As the IPCC (2001) states, "the impacts of climate change will fall disproportionately upon developing countries and the poor persons within all countries…. Populations in developing countries are generally exposed to relatively high risks of adverse impacts from climate change. In addition, poverty and other factors create conditions of low adaptive capacity in most developing countries."

An increasing understanding of, and concern over, the impacts of climate change continue to drive the calls from scientists, analysts, large parts of the public, and the media for controlling the build-up of GHG in the atmosphere. Yet, several characteristics of the climate problem contribute to its complexity and to the difficulties in tackling it:

1. Scale: Given the uncertainty ranges of climate sensitivity, a 50% probability of staying below a $2^{o}C$ warming requires stabilization at 450 ppmv CO_2-equivalent (Tirpak et al., 2005). The magnitude of the task becomes obvious when one considers that middle-of-the-range emission scenarios suggest by the year 2100, the atmospheric CO2 concentrations would be about 650-750 ppmv (up from about 380 ppmv in the year 2000). Thus, avoiding "dangerous climate change" will indeed be an arduous task.
2. Global nature: Due to the long-range movement of GHG gases and atmospheric mixing, emissions from all part of the world contribute to GHG-induced warming. This means that solving the climate problem requires cooperative action by all countries worldwide.
3. Long lifetime of gases: Most of the GHGs have a significant half-life in the atmosphere. This builds inertia into the system in that emission from today will continue to have an impact on the climate system for coming decades.[178] This also means that it is more difficult to engage in a "wait-and-see" strategy (or at least, engaging in such a strategy will have repercussions).
4. Strong linkages between GHG emissions and human activity: Buildup of GHGs is linked to a wide range of human activities – this includes enhancement of "sources" of CO_2, methane and other gases as well as reduction of "sinks" (especially forests). This means effort to mitigate the problem will require significant changes in human activity, underpinned by technological advances as well as cultural and behavioral changes.
5. Uncertainties: While there is widespread consensus on some key issues (such as "are there clear signals of greenhouse warming?" and "are human activities driving climate change?"), there still remain a number of uncertainties surrounding various aspects of the climate problem. These include uncertainties about the flows of GHGs, the relationship between GHG accumulation and warming (i.e., what is the sensitivity of the climate system to GHG buildup) and, and the nature and magnitude of eventual impacts.
6. Mismatch between contributors to the problem and those suffering impacts: An additional twist regarding the climate problem relates to the fact that not all countries (and groups within countries) get affected equally (and in the same way) by a changing climate. While industrialized countries are responsible for the majority (almost two-thirds) of today's global GHG emissions and an even greater fraction of the GHG buildup in the atmosphere, it is developing countries that are likely to bear the brunt of the climate impacts. Countries such as small-island states will suffer catastrophic impacts that threaten their very existence, and many African and other tropical countries will

[178] The observed rise of global mean temperatures is due to the fact the current GHG concentrations are well-above pre-industrial levels as emissions from the past century have contributed to the accumulation of GHGs.

suffer serious negative impacts. The mitigation of the GHG emissions, similarly, will affect different countries in a different fashion, both in terms of modification of industrial and other activities that result in these emissions and in terms of the markets for energy sources (especially fossil-fuels). Lastly, different countries have different capabilities to adapt to climate change – countries such as the Netherlands that have the technical and institutional capabilities to respond to sea-level rise is likely to suffer far lower impacts than a poor country like Bangladesh with little response and adaptive capacity.

Given the enormous threat of global climate change, most countries of the world[179] have already accepted an international treaty—the United Nations Framework Convention on Climate Change (UNFCCC)—to start an intergovernmental process for mitigating climate change and for adapting to inevitable temperature rises. The Convention recognized that the climate system is a shared resource whose stability can be affected by industrial emissions of greenhouse gases, and set an ultimate objective of stabilizing greenhouse gas emissions "at a level that would prevent dangerous anthropogenic (human induced) interference with the climate system … within a time-frame sufficient to allow ecosystems to adapt naturally to climate change, to ensure that food production is not threatened, and to enable economic development to proceed in a sustainable manner."[180] In order to meet this goal, the Parties to the Convention had "common but differentiated responsibilities" and had to work "on the basis of equity" and in accordance with their respective capabilities—"[a]ccordingly, the developed country Parties should take the lead in combating climate change and the adverse effects thereof."[181] Furthermore, India as well as China and other G-77 countries have also long argued, but without much success, for a per-capita-based allocation framework as the appropriate approach for thinking about GHG emission reduction commitments.

Recently, a large number of nations[182] have ratified an addition to the UNFCCC—the Kyoto Protocol—which has legally binding targets for Annex I countries (as listed in the UNFCCC) to limit or reduce their GHG emissions through domestic policies and measures. These targets add up to a total cut in their GHG emissions of at least 5% from 1990 levels in the commitment period 2008-2012. In order to meet these goals, the Protocol allows Annex I countries to utilize three other mechanisms to supplement their domestic policies and measures: 1) Emission Trading – whereby Annex I countries can trade emission reductions amongst themselves, 2) Joint Implementation – an Annex I country can help implement an emission-reducing project in another Annex I country and reap benefits of the resulting emission reductions, and 3) Clean Development Mechanism – an Annex I country can implement a project in a non-Annex I country and use the resulting certified emission reductions (CERs) to meet its target.[183] The Protocol came into force in February 2005.

---

[179] 189 countries having ratified the UNFCCC.
[180] http://unfccc.int/resource/docs/convkp/conveng.pdf. See: http://unfccc.int/essential_background/feeling_the_heat/items/2914.php for more information about the Convention.
[181] http://unfccc.int/resource/docs/convkp/conveng.pdf.
[182] 164 countries as of October 2006.
[183] Details about these mechanisms can be found at: http://unfccc.int/essential_background/kyoto_protocol/items/3145.php.

Although only some of the Annex I countries are legally bound to reduce emissions at this point in time (as per the Kyoto Protocol),[184] there is little doubt that all countries will eventually have to contribute to mitigating climate change. While developing countries have not had to take on any GHG-mitigation commitments so far, there is immense pressure on them to do so, driven in large part by the United States which has linked its own intransigence to lack of formal commitments by developing countries. While this flies in the face of the UNFCCC commitment requiring industrialized countries to take the lead in combating climate change, political expedience may require developing countries to seriously consider taking on commitments in the period following the Kyoto Protocol (i.e., post-2012). At the same time, given that these countries will likely suffer disproportionately from a changed climate, it is also in their interest to work towards limiting climate change.

The emissions from combustion of fossil fuels (mostly in the energy sector) are a major contributor to climate change, especially since fossil fuels account for almost 80% of the global energy supply. Thus, a significant reorientation of most national energy systems may indeed be necessary for mitigating climate change. GHG mitigation will require the implementation of a range of technologies and practices (e.g., more efficient conversion and use of energy, low GHG-emitting technologies, carbon capture and storage, and improvements in land use, land-use change, and forestry practices), many of which currently exist. But the implementation of new, improved, or existing technologies with low climate impact is limited by a number of barriers: economic, political, technical, institutional, financial, behavioral, etc. The economics of GHG mitigation are clearly the dominating issue, given that the costs of meeting the appropriate stabilization targets may be substantial (with the exact cost depending on the specific pathway): reaching a stabilization target of 550 ppmv is estimated to be between 100 and 800 trillion dollars over the next century;[185] reaching a tighter stabilization target of 450 ppmv—a level most likely required to avoid dangerous climate change—could cost between 350 and 1750 trillion dollars (IPCC, 2001).

For developing countries, GHG-mitigation challenge comes at a time when there are already other more pressing challenges facing the energy sector, as discussed earlier in section 3.1. At the same time, a climate-based reorientation of the energy sector will require new technologies (such as those for clean-coal-based power generation, carbon capture and storage, and non-GHG-emitting options such as solar photovoltaic) that will mostly be developed in the industrialized countries since developing countries may not have the appropriate technological capabilities to do so. Therefore, discussions of technology development and 'transfer' have become contentious in climate change negotiations.

3.4.1 Carbon trends in Indian energy economy

We have already discussed in section 3.1.1 the broad contours of India's energy consumption, as it relates to country's development trajectory. Given that India's energy consumption will increase as the country develops, meeting any climate commitments will necessitate a greater focus on the efficiency of the energy economy as well as its carbon dependence.

---

[184] United States and Australia are two key Annex I countries that have not signed the Kyoto Protocol.
[185] Based on 1990US$, present value discounted at 5% p.a. from 1990-2100.

India's energy use per unit GDP (energy-intensity) is lower than many other major countries and close to the OECD and global averages, as shown in Figure 22. While the Indian energy-intensity has been declining slowly over the past few decades,[186] the decline is moderate in comparison to China, which has seen a dramatic reduction in its energy intensity, albeit from a much higher starting point.

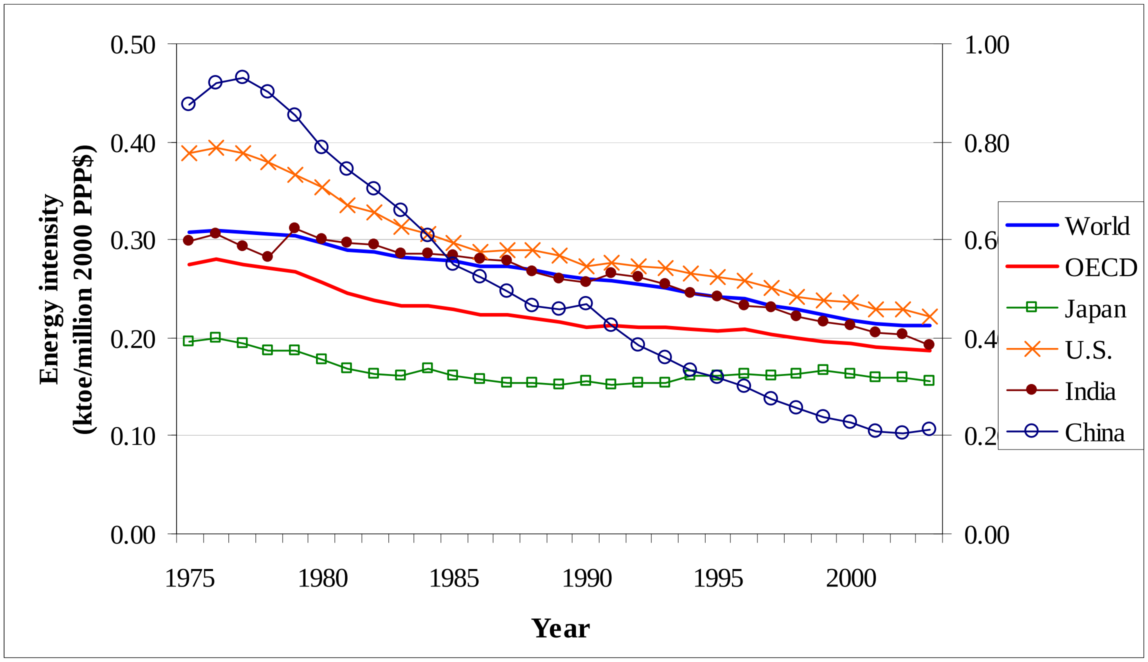

Figure 22: Energy-Intensity trends for key countries/groups, 1975-2003.
Source: (Marland et al., 2007; World Bank, 2007).

However, despite the lowering energy-intensity, India's overall CO_2 emissions have been increasing at a compounded annual growth rate of 4.9% from 1990 to 2003 (Marland et al., 2005), in comparison to ~4.5% for China, ~1.6% of US, and ~1.5% globally (see Table 15). More recently (from 2000 to 2004), India's emission growth rate slowed down to 3.8%, as has the U.S. with 0.3%; however, Chinese emission rates increased dramatically to 10.7% over this period (Marland et al., 2007). Moreover, India's contribution to annual global emissions remained at about 4.5% between 1999 and 2004; in contrast, China's contribution increased from 13% in 2000 to 17% in 2004 (Marland et al., 2007).[187] Thus, although India is now the 4th largest emitter of CO_2 worldwide, its total emissions are still about 1/5th and 1/3rd of U.S. and China, respectively. Furthermore, India's carbon emissions on a per-capita basis are almost 1/20th that of the United States and less than half that of China.

[186] Two factors account for declines in energy intensity worldwide: one, improvements in the efficiency of energy conversion and end-use; and two, structural shifts in the economy away from energy-intensive activities, such as manufacturing, towards the service sector as has been the case in most industrialized countries over the past few decades (although industrializing countries such as South Korea provide a counter-example, in that energy-intensive activities such as manufacturing are contributing a greater share of the GDP than a few decades ago).

[187] Therefore, it is important not to juxtapose India and China together when one is discussing responsibility for climate change.

	Carbon emissions (ktC)		C/capita (tons)		C/GDP (tons C per million 2000 international PPP$)		C/TPES (tons C/toe)	
	1990	**2003**	**1990**	**2003**	**1990**	**2003**	**1990**	**2003**
India	186057	344688	0.21	0.33	132	121	0.51	0.63
China	654710	1159593	0.58	0.90	355	179	0.76	0.84
US	1315008	1621634	5.41	5.57	102	158	0.68	0.71
Japan	292221	335919	2.25	2.62	186	101	0.66	0.65
World	6196000	7504000	1.18	1.19	187	151	0.72	0.71

Table 15: Carbon emissions of India, China, U.S., Japan, and the World.
Source: (Marland et al., 2007; World Bank, 2007).

The carbon factor of the Indian energy economy (carbon emission per unit energy use) has risen significantly over the past two decades (as it has for China), presumably because commercial, fossil-based, energy supplies have been contributing a greater share to the overall energy supply (see Figure 23). Overall, the carbon intensity of the Indian economy remains relatively low (~70% of China and 80% of US) but with only a slow rate of improvement.

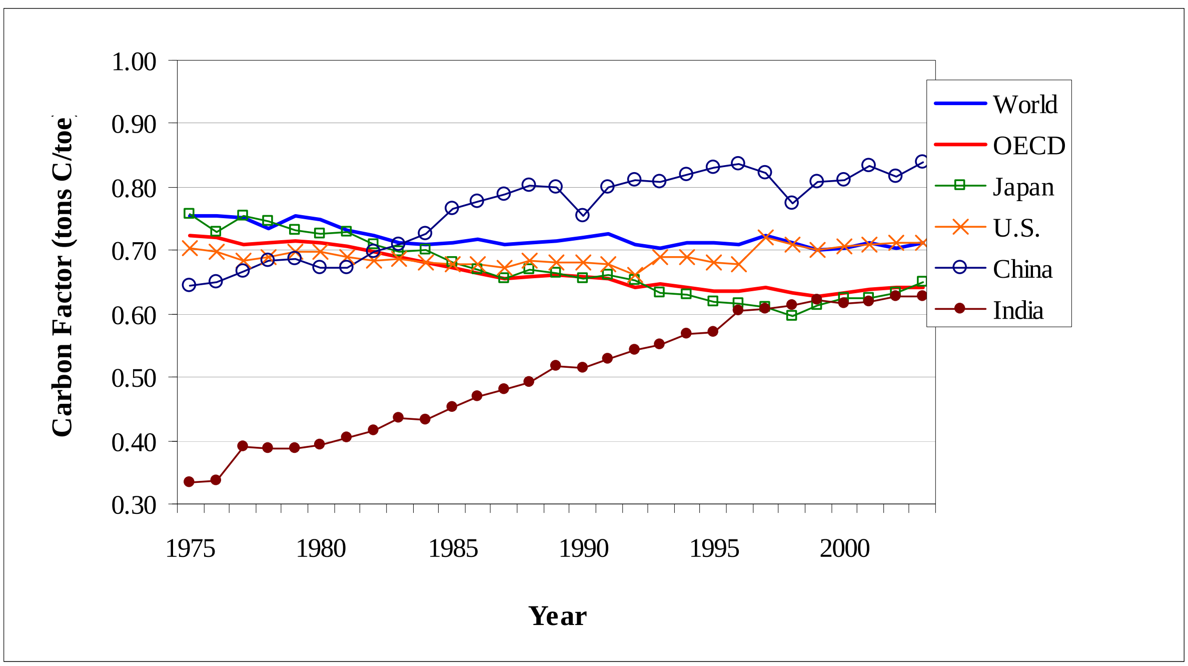

Figure 23: Carbon-factor trends for key countries/groups, 1975-2003.
Source: (Marland et al., 2007; World Bank, 2007).

In terms of role of coal in CO_2 emissions, India's National Communication to the UNFCCC indicates that coal contributed about 62% of India's total CO_2 emissions of 817 Tg in 1994, with the contribution of the energy transformation (electricity generation and petroleum refining) being 43% (MoEF, 2004). The trend for the annual CO_2 emissions from fossil-fuel use in India is shown in Figure 24. Contribution of solid fuels (coal) to the total fossil-fuel-based emissions is now about 70% (Marland et al., 2007).

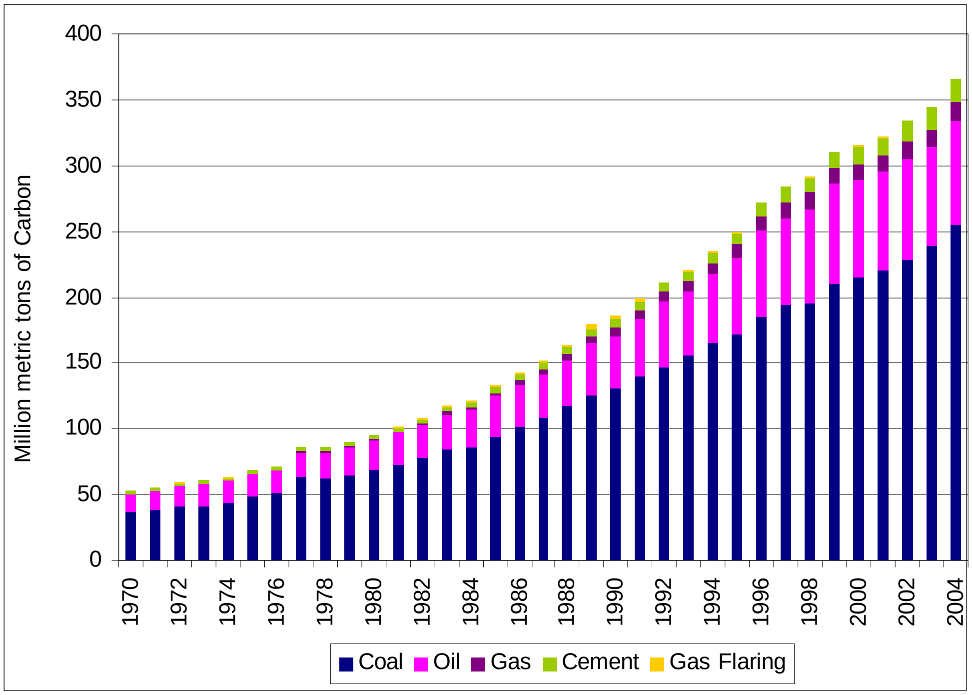

Figure 24: Indian CO_2 emissions from fossil fuel use (1970-2004). Source: (Marland et al., 2007).[188]

3.4.2 Climate Change and India

Climate change is an important issue for India, given the range and magnitude of the possible impacts. It is predicted that average surface temperature in India will increase between 2.3 to 4.8°C for a doubling of pre-industrial CO_2 levels (Dinar et al., 1998). Other predicted climatic changes with significant implications for India include changes in monsoon precipitation patterns as well as rise in extreme rainfall events, coastal storms, and droughts. Such changes in the climate could have enormous human, ecological, and economic impacts on the country. For example, more intense rainfall could lead to floods and landslides and contribute to greater erosion. Rising temperatures in South Asia will lead to reductions in snow cover and melting of glaciers in the Himalayan region, which will have serious implications for water resources in India (and other South Asian countries); rising temperatures will also lead to changes in disease patterns and affect agricultural productivity. Water availability will become an important issue with changes in rainfall patterns—already water use in urban areas is competing with water needed for agriculture, and underground aquifers are depleting at a rapid rate. Given that the country has about 7000 km of coastline, more frequent and intense coastal storms could cause enormous damage to human settlements, coastal ecosystems, and result in loss of life; similarly, a rise in sea levels, driven by increases in the global mean temperature, will have significant implications for coastal communities. The vast number of poor in India, who are particularly vulnerable to these kinds of climatic impacts, will be exposed to enormous risk (IPCC, 2001).

[188] Other calculations of India CO_2 emissions by Garg et al. (2001a) and (2004) are about 15-20% less than the emissions calculated by Marland et al. (2005).

Given the high impact of climate change on the country, India has been engaging with the international community on dealing with climate change. India signed onto the United Nations Framework Convention on Climate Change (UNFCCC) treaty (ratified in 1993), and it also ratified the Kyoto Protocol in 2002. At present, India has no commitments under Kyoto Protocol, although there are a range of ongoing GHG-mitigation projects in the country under the umbrella of the Clean Development Mechanism. India has been actively involved in one of the Protocol's key mechanisms of meeting the goals – the Clean Development Mechanism (CDM). As of April 2006, India had 206 registered projects (out of 595 registered projects worldwide).[189] India has also been making an effort to improve its industrial performance, thereby reducing its GHG emissions—since 1995, India's energy, power, and carbon intensities have all begun to decline (Chandler et al., 2002). Growth of India's energy-related CO_2 emissions has reduced by nearly 111 million tons of CO_2 over the last decade (1990-2000) through policy initiatives that aimed at economic restructuring, enforcement of clean air laws, and renewable energy programs (Chandler et al., 2002).

India has also recently joined US-led Asia-Pacific Partnership for Clean Development and Climate (along with Australia, the People's Republic of China, Japan and South Korea). This is a "new results-oriented partnership" that aims to "allow [these] nations to develop and accelerate deployment of cleaner, more efficient energy technologies to meet national pollution reduction, energy security and climate change concerns in ways that reduce poverty and promote economic development."[190] Critics, however, suggest that this move may undercut the multilateral process to tackle climate change under the UNFCCC through binding GHG-mitigation agreements and therefore, in the end, may be counterproductive (Narain, 2005; Dennis, 2006).

Despite all of these international efforts, it is unlikely that India (and China) will be able to avoid taking on some kind of commitments in the near future. As discussed earlier, issues of equity and technology transfer will be important issues as these negotiations continue. The nature and timing of these commitments will be crucial for India's engagement in the post-Kyoto process. Also, given that India's total and per-capita emissions are much lower than China's, it is likely that India will have significant headroom for GHG emissions growth as its economy grows. Nonetheless, early considerations of various options to reduce the country's GHG emissions, especially from the coal-power sector, would be prudent.

Some of the broad options to consider in reducing overall GHG emissions are (a) reducing energy demand through conservation and lifestyle changes, (b) increasing efficiency of energy conversion and end-use processes, (c) switching to less carbon-intensive fuels (renewables, natural gas, etc.), (d) capturing and storing CO_2 from emission sources, and (e) sequestering atmospheric CO_2 by enhancing the natural sinks such as forests, etc. In reality, given the sharp cuts needed in relation to the business-as-usual emissions trajectory, it is likely that all of these options will have to be exercised over time. In the power sector, the reduction of CO_2 emissions can be achieved through increased efficiency of generation, fuel-switching, and carbon capture and storage. The present and continuing prominent role of coal in the Indian power sector will almost necessarily require a focused effort to minimize CO_2 emissions from this sector.

---

[189] See: http://cdm.unfccc.int/

[190] Quotes from President Bush, July 27, 2005. See: http://www.whitehouse.gov/news/releases/2006/01/20060111-8.html

4 Constraints

While the challenges discussed in the previous section are daunting enough, it becomes even more difficult when the constraints facing the Indian power sector are considered. These constraints must be taken into account when devising technological solutions and policies to meet the challenges discussed in the previous sections. The main constraints are:

- Domestic coal issues
- Financial pressures
- Technical capacity
- Institutional issues

These will be discussed more in detail in the following sub-sections.

4.1 Domestic coal issues

Figure 25: Major Coalfields and Mining Centers.
Source: Coal in the Energy Supply of India, © OECD/IEA, 2002.

Indian coal occurs in two main geological horizons, the Permian (Gondwana coals) and the Tertiary. Most of the major coal deposits are Gondwana coals in the eastern and south-eastern parts of India; the Tertiary coal deposits are located in Assam, other north-eastern states, and Jammu and Kashmir (see Figure 25). Indian coal is primarily bituminous and sub-bituminous, although there are nearly 36 BT of lignite resources in Tamil Nadu (Neyveli), Gujarat, Rajasthan, and Jammu and Kashmir.

4.1.1 Resources

Ever since coal was first commercially mined in India in 1774 in Ranjgunj, West Bengal, assessing coal resources in India has been a high priority.[191]

The Geological Survey of India (GSI) and the Mineral Exploration Corporation (MEC) undertakes prospecting surveys in areas with potential coal resources.[192] It is estimated that India has about 22,400 square kilometers (sq. km) of potential coal bearing area; only about 45% (10,200 sq. km) of this potential area has been systematically explored (Ministry of Coal, 2005a).[193] Preliminary exploration using wide-spaced drilling is undertaken by GSI, MEC, and CMPDI under the regional/promotional exploration program.[194] Based on these explorations, coal resources are categorized according to borehole spacing into "Inferred" (borehole spacing greater than 2 km) and "Indicated" (spacing between 1 and 2 km). Depending on the projected coal demand and judgment of coal companies, certain areas are identified for detailed drilling (with borehole spacing less than 400 m) to define the coal seams more precisely and to assess the quality of the coal. Estimates from this more detailed drilling (covering about 50% of 10,200 sq. km of explored area) are called "proved reserves."[195] Table 16 shows GSI's assessment of the coal inventory in India as of January 2005, categorized by depth of coal seams.

Depth (m)	Proved (BT)	Indicated (BT)	Inferred (BT)	Total (BT)	Total (%)
0-300	71	66.5	15	**152.5**	62
300-600	6.5	39.5	17	**63**	25
0-600 (Jharia)	14	0.5	-	**14.5**	6
600-1200	1.5	10.5	6	**18**	7
Total	**93**	**117**	**38**	**248**	**100**
%	38	47	15	**100**	

Table 16: India's Coal Resource Inventory (January 2005).
Source: (Chand, 2005; Ministry of Coal, 2005b, 2005a).

As of January 2005, Indian coal resource inventory stands at 248 BT, with only 38% (93 MT) out in the 'proved' category. Table 17 shows the type of coal within the coal inventory. Coking coal constitutes only about 18% of proven resources, of which only a quarter is of prime coking coal quality. Of the proved non-coking coal resources, superior grades[196] (i.e., A, B, C & D)

[191] In 1836, the first assessments of Indian coal resources were conducted by D.H. Williams of the British Geological Survey for the East India Company and the first comprehensive assessment was done by Cyril Fox in 1934 (Krishna, 1980). In fact, the Geological Survey of India was formed out of initial efforts to map Indian coal resources (see: http://www.gsi.gov.in/odyssey.htm).
[192] The surveys use conventional geological mapping, air photo interpretation, satellite imagery, etc. (Ministry of Coal, 2005a).
[193] It is prognosticated that about 143 BT of coal resources exist in the remaining 55%. In addition, about 67 BT of coal are expected to lie deeper than 1200 m in the Cambay basin. These 210 BT of "prognosticated resources" are not included in the official coal inventory shown in Table 16 (Ministry of Coal, 2005a). India also has about 36 BT of lignite resources (Ministry of Coal, 2006).
[194] The regional exploration program is funded by the Ministry of Mines for GSI, and the Ministry of Coal funds the promotional exploration program for GSI, MEC, and CMPDI (Ministry of Coal, 2005a).
[195] This nomenclature of "proved reserves" is not accurate, as will be discussed later.
[196] Indian coal is priced according its grade. The gradation of non-coking coal is based on a range of useful heat values (UHV) of coal. UHV is determined by the ash content and moisture in coal, and it correlates with the coal's

constitute about a third; the rest being inferior coal (grades E, F & G), which is typically used for coal power plants. Overall, the proved resources of inferior non-coking coal account for about 20% of the total coal resource inventory.

Furthermore, more than 90% of all of the non-coking resources are within 0-600 m of depth. Chand (2005) has noted that most of the recent drillings have been limited to 300 m (62% of the explored coal resources is located within 300 m depth; see Table 16). Coal resources at 300 m depth is accessible through opencast mining, which currently accounts for more than 80% of the coal produced in the country (see Figure 27 below). Hence, detailed drilling and analysis of coal resources seems to be more dependent on the coal industry's views on extraction based on current technology and economic prospects (Ministry of Coal, 2005a), rather than on an independent assessment total coal resources, including those at deeper depths.

Coal Type	Proved (BT)	Indicated (BT)	Inferred (BT)	Total (BT)	Total % of Total Coal
Prime Coking	4.6	0.7		**5.3**	2%
Medium/Semi Coking	11.9	12.8	2.1	**26.8**	11%
Total Coking	**16.5**	**13.5**	**2.1**	**32.1**	13%
% of Total Coal	18%	12%	6%	13%	
Superior Non-coking	26.8	36.6		**63.4**	26%
Inferior Non-coking	49.2	66.9		**116.2**	47%
Total Non-coking	**76.0**	**103.5**	**35.3**	**214.9**	87%
% of Total Coal	82%	88%	93%	87%	
Tertiary coal	0.4	0.1	0.4	0.9	0.4%
Total Coal	**92.9**	**117.1**	**37.8**	**247.9**	

Table 17: Type of coals in the Inventory (January 2005). Source: (Ministry of Coal, 2005b).

In addition, there are several other problems. For example, the coal inventory shown in Table 16 includes reserves that are already depleted due to mining and resources that cannot be mined due to mining, surface, and geotechnical constraints,[197] as well as resources that cannot be mined using current technology (Ministry of Coal, 2005a).[198] Furthermore, classifying resources according to borehole density does not take into account geological complexities and coal seam

gross calorific value. Since grades are assigned to wide ranges of UHV, pricing is not directly proportional to calorific value of coal. See Table 19.

[197] Mining constraints include coal left in pillars, roof and floor of coal seams during underground mining, and coal left in mining benches for opencast mining. Surface constraints include water bodies such as rivers and lakes, railway lines, transmission lines, road highways, villages, towns and cities. Geotechnical constraints include faults, dykes, thickness of coal seam, occurrence of dirt bands within coal seams, and gaseous seams that can catch fire (Ministry of Coal, 2005a).

[198] Sankar Committee Report has pointed out that a clear picture of resources unavailable for mining due to various constraints is often unavailable (Ministry of Coal, 2005a).

heterogeneities. In many cases, drilling does not even extend to the basement of the coal basin, but limited to arbitrary depths (Ministry of Coal, 2005a).

The situation is further complicated with unclear terminology and classification systems, as also highlighted by (Ministry of Coal, 2005a): for example, technical terms such as *'resources'* and *'reserves'* are often misused, with geological resources being treated as 'reserves' (Chand, 2005). Also, the Indian classification system is based primarily on geological evaluations without assessing the quality, mineability, or extractability of deposits. In contrast, the United Nations Framework Classification (UNFC, 2004) denotes reserves to be the economically mineable, technically feasible, and geologically proven part of remaining resources.[199] Furthermore, technical efforts directed towards coal mapping in the country could be significantly strengthened and improved.

Given that there has been no systematic assessment, based on clear definitions, of coal resources in the country, there is considerable uncertainty about the actual amount of coal reserves in India. A recent report from the Ministry of Coal (2005a) notes that "there are conflicting views among experts about the level of availability of coal". It is also quite disturbing that the level of uncertainty regarding India's coal reserves has always remained high, despite exhortations by various expert committees since independence to improve the situation.[200]

There is also considerable uncertainty regarding the techno-economic mineability of India's current coal inventory. Although reserves should ideally be defined for each mine (or coalfield) based on techno-economic-geological analysis, the Central Mine Planning and Design Institute Limited (CMPDIL) has made tentative estimates of extractable resources by making various assumptions about resource-to-production ratios and confidence levels for established coal inventory. These estimates for reserves up to 1200 m are shown in Table 18. According to CMPDIL, only 52 BT (56%) out of 93 BT of proved resources is considered as extractable resources[201] – this is only a *fifth* of the total resources in the country.[202] Furthermore, at least 8 BT has already been depleted due to past mining (CMPDIL, 2001), leaving only about 44 BT as

---

[199] In more detail, proved reserves are the economically mineable part of a recoverable quantity assessed by a feasibility study or actual mining activity usually undertaken in areas of detailed geological exploration. It includes diluting materials and allowances for losses which may occur when material is mined and milled. Appropriate assessments of these reserves, which include feasibility studies, require inclusion of realistically assumed mining, metallurgical, economic, marketing, legal, environmental, social and governmental factors. The assessments must demonstrate, with a high degree of confidence at the time of reporting, that extraction is justified. Detailed geological exploration includes detailed three dimensional delineation of a known deposit achieved through closely spaced sampling. The samplings must establish the size, shape, structure, grade, and other relevant characteristics of the deposit with a high degree of accuracy (UNFC, 2004).

[200] The 1949 Power and Fuel subcommittee report of the National Planning Committee series noted that modern techniques have not been used in assessing coal resources in India (Page 46 of (National Planning Committee, 1949)). The Fuel Policy Committee (FPC, 1974) recommended that urgent efforts must be undertaken to systematically explore coal reserves in the country, so as to reliably establish the extent of available coal. In 1979, the Working Group on Energy Policy noted that "a sustained effort should be made to constantly appraise [coal] reserves and classify them by varieties of coal and categories of reserves" (Prasad, 1979).

[201] A more recent estimate indicates an estimated range of 56 – 71 BT of extractable coal reserves, of which 33 BT are in the 'proved' category (Planning Commission, 2006).

[202] A similar estimate in 1996 showed that only 29 BT were extractable out of 69 BT of proved resources, based on a total resource of 202 BT. The extractable reserves were 42% and 14% of the proved and total resources, respectively (PIB, 2001).

a tentative estimate of coal reserves in India (Chand, 2005). Based on CMPDIL estimates, it is clear that while India may not have as large reserves of coal as has been assumed by many international bodies,[203] it still does have a substantial amount.[204]

	Geological Resources				Tentative Reserves		
Area	**Proved (BT)**	**Indicated (BT)**	**Inferred (BT)**	**Total (BT)**	**Extractable (BT)**	**% of Proved Resources**	**% of Total resource**
Coal India Ltd.	67.71	19.42	4.56	91.69	30.03	44%	33%
Rest of Country	25.25	97.66	33.24	156.15	22.21	88%	14%
Total	**92.96**	**117.08**	**37.8**	**247.84**	**52.24**	**56%**	**21%**

Table 18: Tentative estimates of extractable coal reserves in India.
Source: (Chand, 2005; Ministry of Coal, 2005a).

Depending on rate of domestic coal production and accretion of more coal reserves due to enhanced drillings and more extensive surveys, Indian coal might last anywhere between 30-60 years (Chikkatur, 2005; Ministry of Coal, 2005a).[205] The amount of reserves, and hence the coal lifetime, can be increased – but only with large technological and financial investments in the coal sector, reduced demand of domestic coal, and if the coal consumers (especially power plants) can afford to pay more. Without improvements in coal technology and economics, the existing power plants and the new plants added in the next 10-15 years might consume *most* of the currently estimated extractable coal in the country over the course of their 40-50 year lifespan.[206] The short lifetime is in sharp contrast to the general assumption that Indian coal will last more than 200 years[207] – an assumption which is predicated on extracting all the resources without accounting for technology or economics (Chikkatur, 2005).

Much of the uncertainty regarding Indian coal reserves might be reduced when the current coal resource inventory is reclassified according to UNFC categories. While the Ministry of Coal has already accepted the UNFC system as the new national standard in India,[208] it is yet to be fully implemented in the coal sector. Its adoption, though, might revise the coal reserves downward significantly (Chatterjee, 2003). So, until more reliable data based on the UNFC system is available, considerable uncertainty about the quantity of Indian coal reserves will remain.

---

[203] For example, see: (IEA, 2002a; BP, 2006; EIA, 2006; IEA, 2006a).
[204] India's 44 BT would make it the sixth largest coal reserves in the world – a small drop from being the fourth largest if it had 93 BT (assuming that the coal reserve data for other countries are reliable).
[205] This relatively short lifetime results primarily from a rapid exploitation of current reserves to satisfy the increasing coal demand for power generation (Chikkatur, 2005). Many mines are already being mined unsustainably to cope up with increased demand from power generation (Personal communication. S.K. Chand, 2006).
[206] Existing plants consume about 300 MT of coal annually, and they would consume about 12-15 BT of coal over their lifetime (assuming that the older power plants get replaced with other similar coal plants). Over the next 10-15 years, more than 100 GW of new coal power plants could be installed. These plants would consume about 500 MT annually (assuming a specific coal consumption of 0.75kg/kWh and 75% plant load factor), and 20-25 BT of coal over their lifetime.
[207] See, for example: (BP, 2006), (Shahi, 2003), (Sagar, 2002) and http://www.cslforum.org/india.htm.
[208] In 2003, the Ministry of Mines amended the 1988 Mineral Conservation and Development Rules according to the UNFC system.

4.1.2 Production

As mentioned earlier, coal has been produced in India for more than 230 years. By the early 1900s, annual coal production was limited to 6 million tons, with consumption dominated mainly by the railways, which used high-grade steam coal in locomotives (Krishna, 1980; IEA, 2002a); just prior to Independence coal production was nearly 30 MT (Planning Commission, 1952). Prior to nationalization of coal mining (1971-73), most of the coal mines were in the private sector. Since nationalization,[209] coal production has increased more than five-fold, with an annual production of 377 MT in 2004-05 (see Figure 26).[210] Much of the production since nationalization has been from the state-owned collieries of Coal India Limited (CIL) and Singareni Collieries Company Limited (SCCL) – currently, about 95% of coal production is from CIL and SCCL. Also, coal production has been dominated by production of non-coking coal, as coking coal reserves in the country quite limited (see Figure 26 and Table 17)—the increased production of non-coking coal was mainly due to increasing demand from the power sector.

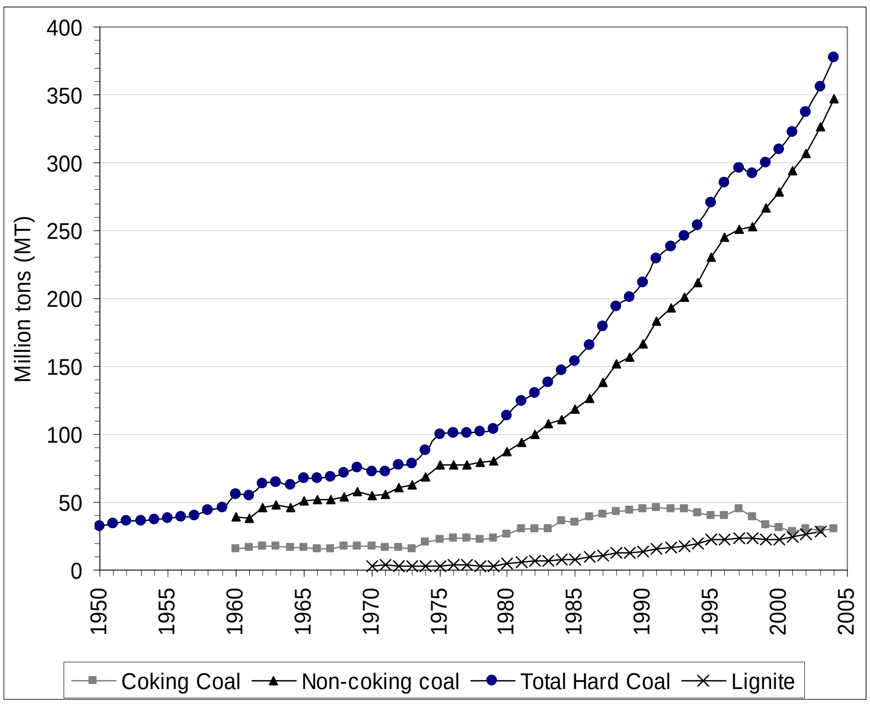

Figure 26: Coal Production in India. Hard coal data excludes lignite production. Source: The data from 1950 to 1960 is from various national Five Year Plans (planning commission) and the data since 1961 is from Ministry of Coal Annual Reports (1999-00, 2003-04, 2005-06). Data for lignite is from (MOSPI, 2005).

Generally, there are two main methods for extracting coal: opencast (surface) mining and underground mining. In opencast mining, the coal is mined in an earth-moving operation by excavating the overburden up to the coal seams and then removing the coal using draglines, shovels, and dump trucks. Opencast mining is advantageous because of greater recovery of in-situ resources, high productivity, low costs and labor intensity, and better workplace conditions

[209] Ostensibly, the nationalization of coal industry was aimed to bring about a coordinated, rational and scientific development of the coal industry, a massive and rapid increase in coal production to meet the needs of consumers, and an optimum use of coal reserves (Gupta, 1979).

[210] In 2003-04, about 28 MT of lignite was produced (Office of Coal Controller)

(Ward, 1984; Buchanan and Brenkley, 1994); however, this type of mining has enormous environmental impacts. Typically, opencast mining is used for coal seams within 300 m of depth, although deeper mining is possible.[211] In contrast, underground mining, which is typically used for extracting very deep coal seams, involves the construction of a vertical shaft or slope mine entry to the coal seam and then extracting the coal using bord-and-pillar[212] or longwall techniques (Ward, 1984). Underground mining is relatively more labor intensive and it is not possible to extract all of the coal – anywhere between 50-90% of the coal can be extracted depending on particular seam characteristics. Some of the problems with underground mining include poor workplace environment,[213] explosions, subsidence, aquifer disturbance, mine water disposal, etc. (Buchanan and Brenkley, 1994).

Although the initial production of coal was based on underground mining in India, much of the increased production since the 1970s has come from opencast mining (see Figure 27). Underground mining has essentially stagnated (and with production decreasing) over the past decade.[214] The increased emphasis on opencast mining has led to faster production rate and reduced mining losses, although it has reduced coal quality as shale and other materials often get mixed up with coal.

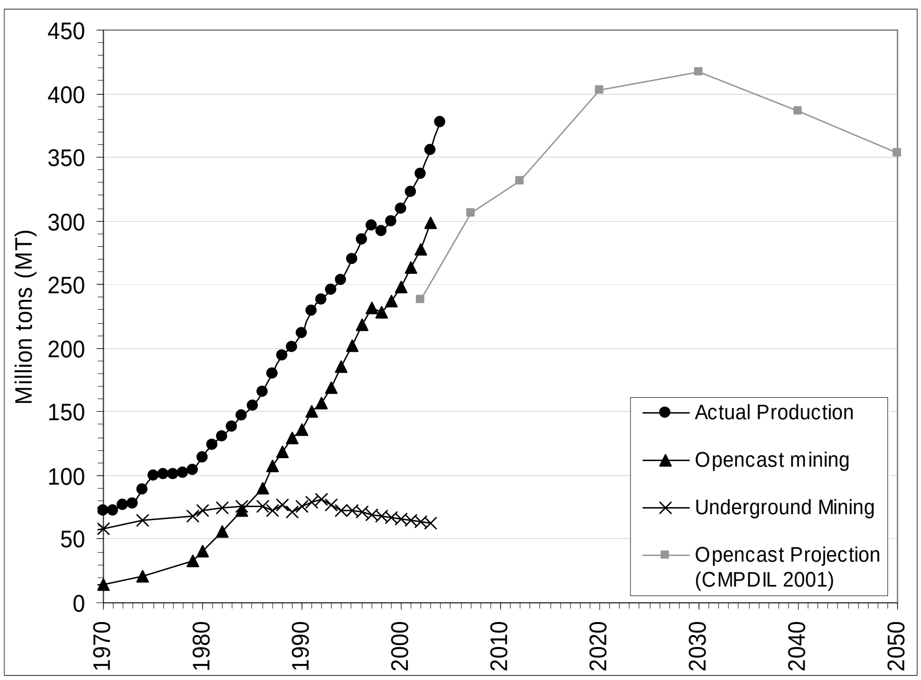

Figure 27: Production of coal by mining technology. Actual production by opencast and underground mining technology is shown, as well as the future projections by CMPDIL (2001) for opencast mining. Source: The total

[211] The cost of opencast mining increases proportionally with the overburden ratio, which is ratio of overburden thickness to the coal seam thickness and relative density (Ward, 1984).

[212] Also known as room-and-pillar and pillar-and-stall. Bords are underground roadways using which coal is extracted, and pillars are made of coal that is left to support the overburden on top. Deeper the coal seam, thicker the pillar size.

[213] See Chapter 6 of (U.S. OTA, 1978).

[214] Since 1991, production from underground mining has been decreasing at an average rate of 1.5 million tons per year.

production data is from Annual Reports of Ministry of Coal (1999-00, 2003-04, 2005-06); opencast and underground data is from CMIE (1995; 2005) and TERI (1986); and the future projections is from CMPDIL (2001). The CMIE data for underground and opencast mining does not exactly match the total production data from the Ministry of Coal.

Opencast production, which will dominate coal production in the near-to-medium term, is expected to peak by 2030 and slow down (CMPDIL, 2001)—primarily because of reduced reserves at shallow depths (see Figure 27). In addition, the unreliability of extractable reserve estimates can impact coal mining projects, as developers will be unwilling to take up projects without better data (Ministry of Coal, 2005a). In addition, environmental and social damages resulting from open cast mining is another important constraint for future open cast mining. Hence, many analysts have called for more investments and planning in underground coal production in the country (Chand, 2005; Ministry of Coal, 2005a).

4.1.3 Consumption

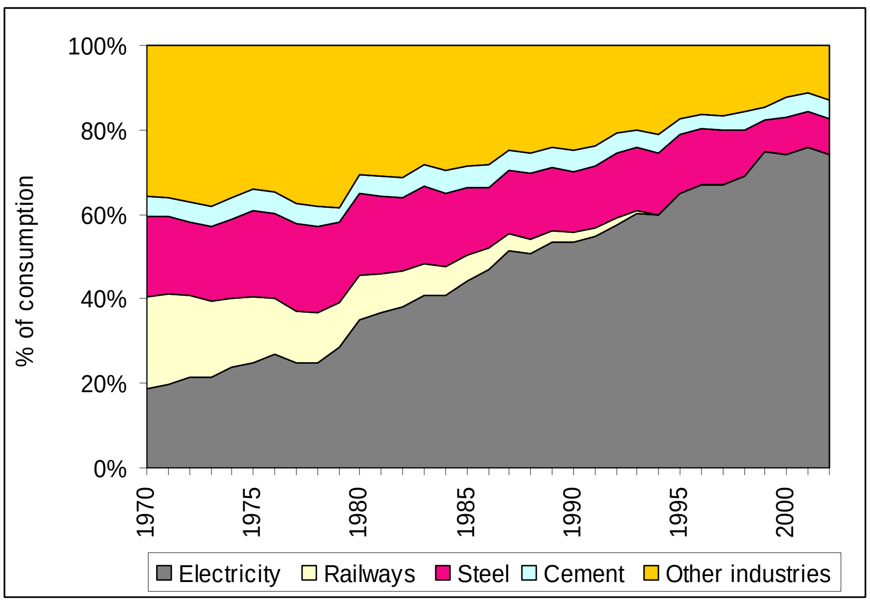

Figure 28: Coal consumption by consumers (1970-2002). Other industries include paper, textiles, jute, bricks, coal for making soft coke, colliery, fertilizers & other smaller industries. Source: (MOSPI, 2005).

Concurrent with coal production, coal consumption and demand has also grown enormously, dominated by the electricity sector. Starting in the 1970s, coal-based thermal power plants were rapidly installed (see Figure 2), and demand for thermal coal increased. In 1970, electricity generation consumed about 13 MT (less than 20% of total coal consumption), and it currently (in 2003) consumes about 280 MT (nearly 75% of total consumption); see Figure 28. The railways, which entirely dominated coal consumption in the second half of the nineteenth century, only accounted for about 20% of consumption in 1970, and direct coal consumption by the railways ended by the mid-1990s, as the railways became entirely based on electricity and diesel. The iron and steel industry, which primarily consumes coking coal and some high-grade non-coking coal, is the second largest consumer of domestic coal, although its consumption with respect to total consumption has decreased from 20% in 1970 to about 8% in 2003. Much of the coal imports are being used by the steel industry as domestic coking coal supply has reduced since the mid-1990s (see Figure 26). The third largest consumer of coal is the cement industry, which consumes between 4-5% of total consumption. Other consumers include the fertilizer industry (consuming nearly 4-5 MT of coal per year since the 1980s; (CMIE, 2005)), the textile industry (include jute and jute products), the paper industry, the brick industry, and other smaller consumers (including domestic consumers).

4.1.4 Future Demand

While domestic production of coal might become limited in the future, its demand is likely to increase dramatically. Already, coal demand – driven primarily by coal power plants – has been outstripping supply: over the two decades, demand has increased at an average annual rate of 5.7%, while production has only increased at 5.1% (Planning Commission, 2002b).[215] The Mid-Term Assessment for the Tenth Plan (2002-2007) notes that the annual growth rate for coal demand is expected to be 6.1% (2002-2007), whereas the production growth rate is expected to be only 5.7% (Planning Commission, 2005). Hence, there is a gap with between coal demand and supply—a gap that is projected to increase in the short-term (Ministry of Coal, 2005a). Over this past year, many power plants, including National Thermal Power Corporation (NTPC) plants, have pulled back on generation and partially shutdown because of coal supply shortages and critically low coal stock levels.[216] NTPC had a loss of 3.6 TWh in 2004-05 – much of it in their Eastern Region plants – because of coal shortages (CEA, 2005c). While these shortages might be considered as being temporary – a result of strikes, low productivity in domestic coal mines, and a slowdown in commissioning of new mines at CIL – they (and power plant shutdowns) might also be harbingers of a future where domestic coal supply is indeed limited.

Recent scenario-based projections of coal demand indicate that coal consumption in the power sector could be in the range of 380-500 MT by 2012 (CEA, 2004a).[217] Longer term scenarios from the Planning Commission (2006) have indicated that annual coal consumption by the power sector might range between 1 to 2 billion tons by 2031-32, with the total coal demand varying anywhere between 1.4 and 2.7 BT (assuming coal calorific value of 4000 kcal/kg and 8% GDP growth.[218] Coal demand projections by various other agencies are also indicated in Figure 29. Furthermore, washing of coal effectively increases the run-of-mine (ROM) coal requirement for the same level of power generation (Ministry of Coal, 2005a). The additional ROM coal requirement resulting from the use of washed coal must be factored into the coal demand estimates for power generation.

[215] During the Ninth Five Year Plan (1997-2002), coal demand was only 2% because of reduced coal-based capacity addition and the financial insolvency of the SEBs (Planning Commission, 2002b).

[216] For example, see: "Coal shortage: NTPC units in critical stage" Hindu Business Line, March 19, 2005; "Thermal plants' coal shortage worsening" Hindu Business Line, April 4, 2005; "Power crisis likely to continue — Coal, gas shortage results in 2 b units loss" Hindu Business Line, May 4, 2005; "Shortage of coal hits power generation at RTPS" The Hindu, May 7, 2005.

[217] Under a base-case scenario for 2012, fuel consumption in the thermal power sector is projected to be 420 MT of domestic coal, 4 MT of imported coal, 30 MT of lignite, and 16 and 9 billion cubic meters of gas and LNG, respectively. The low value of 390 MT is for a scenario with increased energy conservation and the high value of 500 MT for a scenario with high GDP growth (CEA, 2004a).

[218] Coal demand of 2.5 BT occurs in a scenario where coal is the dominant fuel of choice; the 1.5 BT occurs in a scenario where nuclear, hydroelectricity, gas, and renewables resources are forced and demand side management, coal use efficiency, transport efficiency are all increased (Planning Commission, 2006). It is the considered opinion of the Integrated Energy Policy Committee that by 2030, the annual coal demand will be about 2 BT (Ministry of Coal, 2005a).

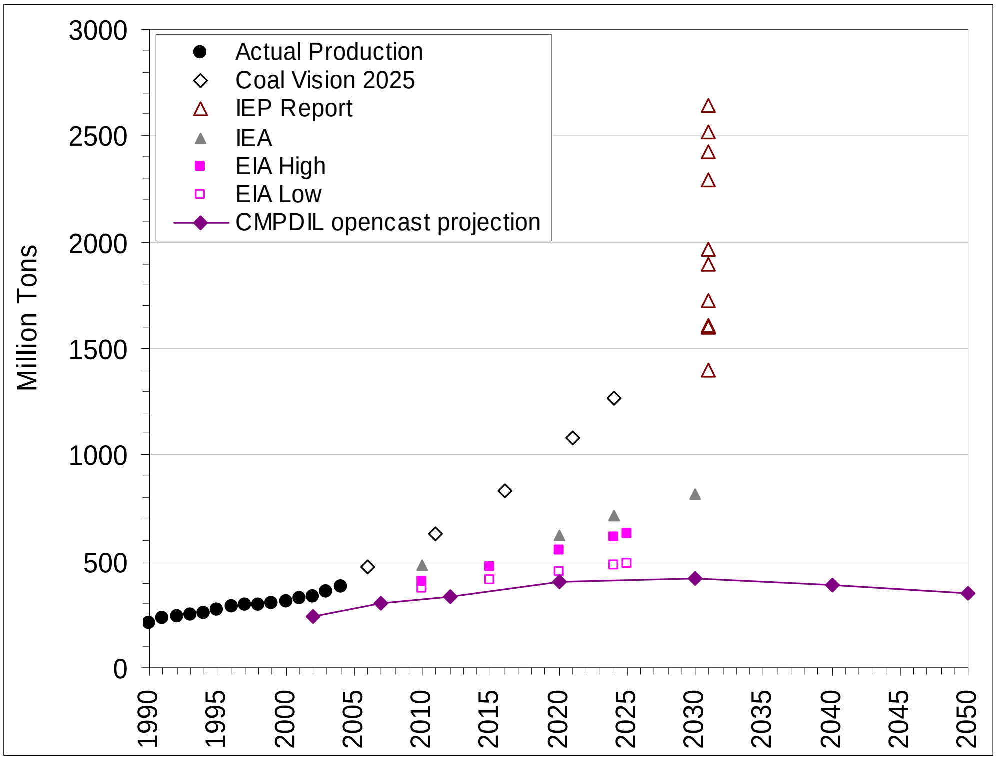

Figure 29: Projected future demand for coal in India. Projections from Indian agencies (Coal Vision 2025 from the Ministry of Coal and the Draft Integrated Energy Policy (IEP) from the Planning Commission, both assuming 8% annual GDP growth) project higher coal demand than the projections from international energy agencies (IEA and EIA). Coal demand based on various scenario projections from the IEP report are shown above (open triangles), assuming coal calorific value of 4000 kcal/kg. Source: (Planning Commission, 2006). The demand projections are contrasted with the projected CMPDIL (2001) domestic coal production using opencast mining (closed diamonds); the data is same as in Figure 27).

In contrast to these demand projections, the Planning Commission (2006) expects domestic production of coal and lignite to be only about 1.4 BT by 2031-32.[219] As discussed earlier, opencast production is likely to peak by 2030 and slow down (CMPDIL, 2001), which implies that India must invests heavily in underground mining and increase its coal imports. It is likely that coal imports will increase dramatically over the next 20-25 years – anywhere between 11% to 45% of total coal demand (i.e., coal imports of 70-to-450 MTOE) (Planning Commission, 2006) – a significant deviation from the current situation, where imported coal is only about 6% of consumption.[220] Current imports are primarily for coking coal that is used in the steel industry, although the power sector has recently been importing more coal to mitigate coal shortages (see Figure 30). However, there are several barriers for importing coal: a) coal imports have custom duty of 5%, b) the economics of coal imports are viable primarily at coastal locations that are far from domestic mines, c) limited port infrastructure for import of coal, d) the poor financial condition of State utilities, e) NTPC, which is the single largest consumer of

[219] Interestingly, the Planning Commission's 1.5 BT of projected coal production is more than three times higher than the CMPDIL (2001) projection for production from opencast mining in 2030 (see Figure 29).
[220] In 2003-04, a total of 24 MT of coal was imported from Australia, Indonesia, South Africa, and China (IEA, 2002a; Ministry of Coal, 2004).

thermal coal, has most of its capacity at the pithead or inland locations, and f) the typically higher sulfur content of imported coal (Sethi, 2003).

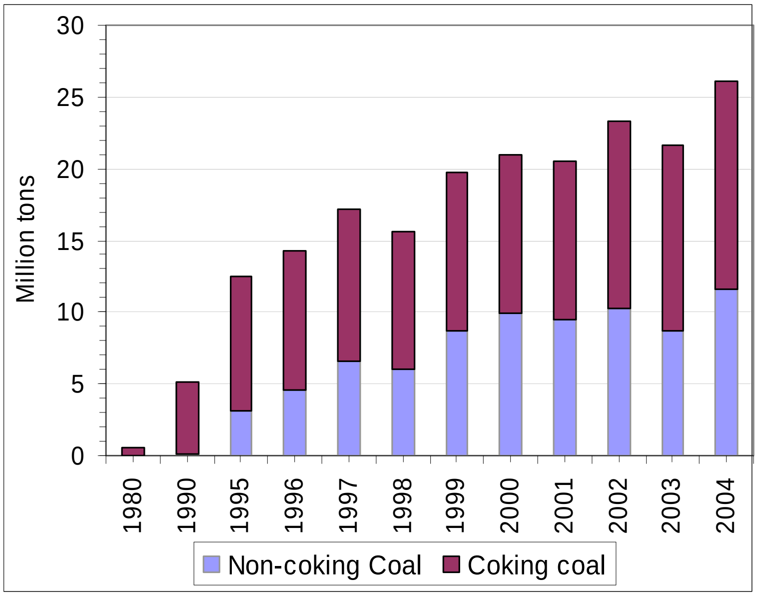

Figure 30: Import of coking and steam coal in India. Data from 1980 to 1998 is from IEA (2002a) and from 1999 to 2004 is from Ministry of Coal annual reports (2003-04 and 2005-06).

Thus, the question of domestic coal availability appears to cast a shadow over the long-term energy security of India. It is clear that domestic coal will continue to the dominant fuel for at least the next 30 years, but not necessarily in the long term (greater than 50 years).

4.1.5 Transport of Coal

Given that coal in India is located in few locations (see Figure 25), transport of coal from mining centers is a very important issue. Future increases in production of coal must occur concurrently with increased development of necessary transport infrastructure. Currently, long-term and short-term supply of coal to the "core" consumers (power and cement industries) are determined by a "Standing Linkage Committee" in the Ministry of Coal, which decides the provision of supply linkages (mode and quantity) from specified mines to individual power and cement plants.[221] The supply of coking coal to steel industries used to be allocated by the Coal Controller; however, the steel companies themselves arrange for supplies with CIL and SCCL on the basis of previous linkages and supply commitments. Supply to large "non-core" consumers is based on another linkage committee, the brick-kilns, domestic consumers, and other small industrial units are left without any formal supply linkages and they readily buy coal from the

[221] The standing linkage committee has the Additional Secretary in the Ministry of Coal as the Chairman, and representatives from CIL, SCCL, CMPDIL, Railways, Planning Commission, Central Electricity Authority, Ministry of power, and the Ministry of Industry. The Committee decides the linkage of coal for source of supply, quantum of coal and the mode of transportation. See: http://coal.nic.in/linkage.html.

black-market at high prices. Recently, CIL has setup an electronic-marketing system, whereby small non-core consumers can purchase coal through an e-auction system.[222]

Current transport of coal from the mines to consumers is primarily based on the railways, although road and merry-go-round systems (for industries located close to pitheads) are other key transport mechanisms (see Figure 31). Nearly 50% of coal-transport is handled by the railways; although, the railways used to account for more than three-fourths of transport by the mid-1970s (TERI, 2005). Merry-go-systems have become an important transport mode, as power plants are increasingly located near pitheads. Transport by sea is also important, as major Indian ports handled more than 50 million tons of coal in 2003-04 and 2004-05—with coal accounting for nearly 14-15% of all port traffic (TERI, 2005).

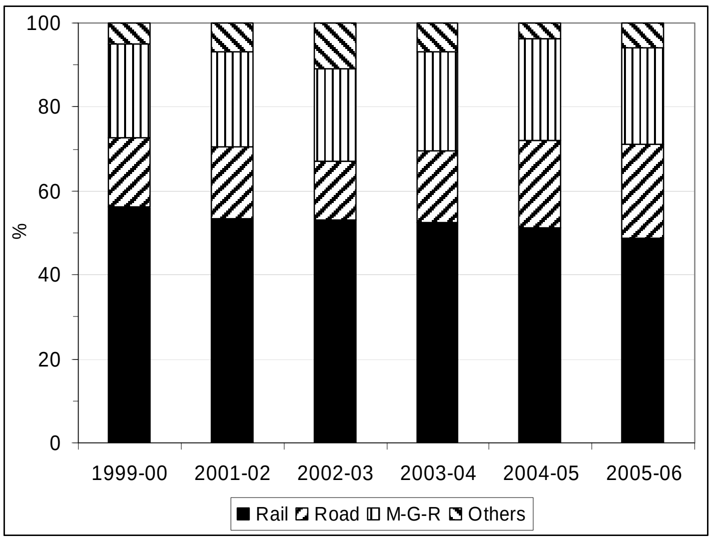

Figure 31: Transport of coal. Recent data for the mode-wise transport of coal is shown. "M-G-R" is merry-go-round systems used to transport coal to pithead plants. "Others" include transport by belt-conveyors, ropeways, rail-and-sea transport, etc. Source: various Annual Reports from the Ministry of Coal.

4.1.6 Coal Cost

The cost of coal sold to power plants can have direct impact on the cost of electricity, especially since fuel costs are passed through directly to consumers under the current electricity regulation regime (Chikkatur et al., 2007a).

The average cost of coal production has steadily increased since the 1970s, despite increases in productivity. The productivity of opencast mining in CIL from 1975 to 2003 has gone up from 0.9 to 6.6 tons/man-shift (TERI, 2004), with the percent of production from opencast mining increasing from about 25% to 80% in the same period (see Figure 27). Nonetheless, the average cost of production in CIL has increased from about Rs. 45 to Rs. 560 in the same period (see Figure 32)—only in the last few years is there any decrease in CIL coal production costs. Although the production cost of opencast mining is about three-to-four times cheaper than

[222] In 2005-06, CIL subsidiaries set aside 10 MT of coal for auction. The price is determined by the "market", with a specific floor price determined by CIL. See: (Ministry of Coal, 2006), http://www.coalindia.nic.in/E-auction%20concepts.pdf and http://policies.gov.in/pol_show_doc.asp?pid=delh254&dno=1.

underground mining, the high cost of production in underground mines has led to higher average production costs. For example: in 1993-94, the cost of underground mining in CIL was about Rs. 710/ton, in contrast to Rs. 240/ton for opencast mining. The weighted average cost for CIL mines in 1993-94 was Rs. 360/ton (CMIE, 1995).

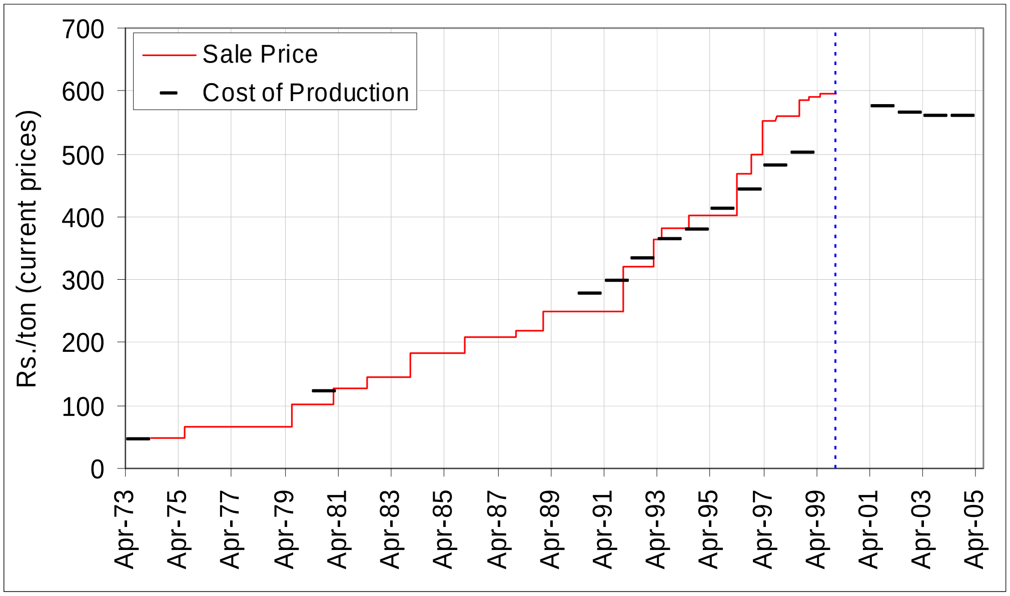

Figure 32: Average cost of production and average sale price of CIL coal. The average cost of producing of ton of coal is shown as dashes that extend from April 1 to March 31 of any particular year. The sale price of coal was determined by the Ministry of Coal and revised periodically (as shown). Since January 2000 (marked by dashed line), the MoC is no longer setting prices. Source: CIL production cost prior to 1993 is from CMIE (1995), from 1993 to 1998 is from Ministry of Coal Annual Report 1999-00, and from 2001 to 2004 is from CIL website.[223] The sale price for CIL coal from 1974 to 1986 is from CMIE (1995), and from 1987 to 1999 is from TERI (2005).

In line with the high average production costs, the average sale price of coal has also been increasing since the 70s (see Figure 32). The sale price of coal has always been a contentious issue throughout the history of coal mining in India. The Colliery Control Order 1945 allowed the government to fix coal prices and prior to nationalization by 1973, coal prices were administratively set low in comparison to production costs (Gupta, 1979; TERI, 1986)—leading to losses for coal mining companies. To allay some of these losses, the government set up the Bureau of Industrial Cost and Prices (BICP) in 1970 to recommend appropriate price of coal, based on production costs.[224] The prices were initially based on an average of production costs of all mines, which led to problems for coal companies with high production costs and allowed for inefficient mining practices to continue (TERI, 1986).[225]

In 1996, the coal prices for coking coal (which was usually more expensive) and higher grades of steam coal was deregulated, and in 2000, a new Colliery Order was passed deregulating the price of all grades of coal. The Ministry of Coal no longer sets the price of coal, but each coal

[223] http://coalindia.nic.in/perf8.htm.
[224] In 1999, the BICP was merged with the Tariff Commission, which was set up in 1997.
[225] For example, companies with higher fraction of underground mines (such as Eastern Coalfields Limited) had higher costs (CMIE, 1995).

company is allowed to set its own sale price based on prevailing market prices. Nonetheless, the prices fixed by the coal companies are, in essence, still "guided" by the government (Ministry of Coal, 2005a). Furthermore, there is very little price elasticity for coal—i.e., coal is always in demand regardless of its price[226]—especially since the electricity sector consumes nearly 75% of domestic coal and electricity is in constant demand even at high prices. Hence, the deregulation of coal prices has occurred in a situation without any effective competition in terms of its supply, as CIL and SCCL dominate the sector by law. Therefore, not surprisingly, this has resulted in an increase in prices without any benefit to consumers, as would have normally resulted from efficiency gains realized through competition (Sethi, 2003).

As of June 2004, the sale price for different grades of non-coking coal is given below in Table 19. These costs are for run-of-mine and they do not include royalty, tax, and cost of transport. The cost of transportation is another important part of the final cost of delivered coal to consumers. Considering the calorific value of coal, the weighted average free-on-rail price of coal for power plants is under $5/million kilocalories, inclusive of royalty of tax; however, the price of delivered coal is about $12-16/million kilocalories, as freight and handling add about $7-$11, depending on distance and mode of transport (Ministry of Coal, 2005a).[227] In contrast, the cost, insurance and freight (cif) price of imported coal is about $13 per million kilocalories at coastal locations (Ministry of Coal, 2005a).

Coal Grade	UHV Band	Bandwidth	Average pithead price (Rs. Ton)	
	kcal/kg	kcal/kg	2000	Range of prices in CIL subsidiaries (June 2004)
A	>6200		1070	1050-1870
B	5601-6200	600	964	940-1670
C	4941-5600	660	792	780-1470
D	4201-4940	740	664	650-1270
E	3361-4200	840	527	510-900
F	2401-3360	960	420	400-710
G	1301-2400	1100	300	290-550

Table 19: Grades and Prices of Indian Coal. The lowest range of prices is from Mahanadi Coalfields Limited and the highest is from Eastern Coalfields Limited and Western Coalfields Limited. Source: (Ministry of Coal, 2005a) and CIL website.[228]

4.1.7 Quality

Indian coal has general properties of the Southern Hemisphere Gondwana coal, which has interbanded seams with mineral sediments (IEA, 2002a).[229] Much of the coal is of low calorific

[226] Sankar Committee Report points out that the price inelasticity exists not only in power generation but also for consumers of high-grade coal, such as iron and steel industries and cement industries (Ministry of Coal, 2005a). Only small-scale brick-kilns and industrial consumers are truly price sensitive and they are willing to pay high costs, as they generally depend on the grey-market, as they are not provided specific coal supply linkages.

[227] The freight charge of $7-$11 per million kilocalories is for distances between 1000 to 2000 kilometers from coal mines (Ministry of Coal, 2005a).

[228] http://www.coalindia.nic.in/pricing.htm.

[229] Similar to all Gondwana coals, Indian coals are highly interbanded, with the thickness of dirt bands ranging from a few millimeters to several meters (Frankland, 2000).

value with high ash content.[230] Run-of-mine coals typically have the following qualities (Sachdev, 1998; IEA, 2002a):

- Ash content ranging from 40-50%, with low iron content and negligible toxic trace elements
- Moisture content between 4 – 20%
- Sulfur content between 0.2 – 0.7%
- Gross calorific value between 2500 – 5000 kcal/kg, with non-coking steam coal being in the range of 2450 – 3000 kcal/kg (Visuvasam et al., 2005).
- Volatile matter content between 18 – 25%.

It is quite clear that the quality of Indian coal is poor and has gotten worse over the past decades (see Table 20).[231] Many times non-coal materials such as shale, stones, and occasionally even iron pieces (such as shovel teeth) have been found in run of mine coal (Sachdev, 1998). Much of the increased ash content is a result of increased opencast mining and production of coal from inherently inferior grades of coal (Ministry of Coal, 2005a). Nearly 65% of the non-coking coal in India have low quality (grade E or below, see Table 19) and amount of ash in coal increases as one moves from the core of the coal seam to its floor (Kanchan, 2006; Nandakumar, 2006)—hence, as the quality of coal seems to worsen with increasing depth of mining. The current practices in opencast mining include dirt bands of thickness less than one meter and some quantities of roof and floor material as part of the mined coal, which leads to high ash content of coals (Frankland, 2000). As equipment for hauling and mining gets larger, there is also more opportunity for dirt bands to get into the mined coal. Furthermore, current coal resource assessments are limited to within 300 m, which implies that opencast mining is expected to dominate production over the next 20-30 years, and thus, coal quality might not improve much without additional cleaning and beneficiation (see section 4.1.9). Furthermore, the current grading system of coals in India does not provide a proper pricing signal for coal producers to improve coal quality (see footnote 196).

PROXIMATE ANALYSIS		**1970's**	**1980's**	**1990's**
FIXED CARBON	%	36.5	32.4	25
VOLATILE MATTER	%	25.5	21.6	18
MOISTURE	%	10	16	12
ASH	%	28	30	45
HHV	kcal/kg	4750	4050	3000

Table 20: Properties of Indian Coal. Source: (Gopinath et al., 2002).

A comparison of Indian coals to Ohio coals indicates the key differences (Table 21). Typical coals from the U.S. and China have about twice the calorific value and carbon content than Indian coals. The low calorific value implies more coal usage to deliver the same amount of electricity. On average, Indian power plants consume about 0.7 kg of coal to generate a kWh (CEA, 2004b), whereas the U.S. power plants consume about 0.45 kg of coal per kWh (EIA, 2001). Indian coal, however, has lower sulfur content in comparison to other coals with low

[230] The Tertiary coals in Assam, however, have low ash, high sulfur and higher calorific values (Krishna, 1980).
[231] The quality of coal in the 1950s was as high as 6000 kcal/cal (Subramanian, 1997).

chlorine (<0.1%) and toxic trace elements including mercury (Sachdev, 1998; IEA, 2002a).[232] Indian coal is also highly reactive and so combustion characteristics are favorable despite the high ash and low calorific values.[233]

Details, %	Kahalgaon 3X500 MW	Simhadri 2X500 MW	Sipat 3X660 MW	Dadri ROM	Dadri Washed	US (Ohio)	China (Long Kou)
Carbon	25.07	29.00	30.72	40.30	45.99	64.2	62.8
Hydrogen	2.95	1.88	2.30	3.19	3.58	5.0	5.6
Nitrogen	0.50	0.52	0.60	0.90	1.00	1.3	1.4
Oxygen	6.71	6.96	5.35	8.20	8.57	11.8	21.7
Moisture	18.5	15.0	15.0	8.69	7.44	2.8	11.0
Sulfur	0.17	0.25	0.40	0.50	0.45	1.8	0.9
Ash	46.0	46.0	45.0	38.2	33.0	16.0	7.7
Calorific Value, kcal/kg	2450	2800	3000	3692	4230	6378	6087

Table 21: Typical coal characteristics at selected Indian power plants, compared to selected Chinese and U.S. coals. Ultimate analysis of coal from four power stations is shown along with analysis of Ohio coal of the United States and Long Kou coal from China. Source: (Visuvasam et al., 2005), except for Dadri ROM and washed coals which are from (Nexant, 2003).

The high ash content also leads to technical difficulties for utilizing the coal, as well as lower efficiency and higher costs for power plants. Some of the problems in power plants resulting from poor and inconsistent coal quality include: damage to conveyor belts, coal crushers, blockage of chutes and feeders, damage to, and high erosion of, pulverizers, reduced availability of coal mills, reduced flame stability, slagging and fouling of water walls, high boiler erosion, increased requirement for land for dumping, and higher emissions (Sachdev, 1998). Some specific problems with the high ash content include high ash disposal requirements (discussed in the next section), corrosion of boiler walls and fouling of economizers, and high fly ash emissions (IEA, 2002a). The high silica and alumina content in Indian coal ash is another problem, as it increases ash resistivity that reduces the ESP's efficiency and increases emissions (see section 3.3.3.1), although the high ash fusion temperature (>1100 ^{o}C) of Indian coals is helpful for reducing slagging in boilers. However, the high ash fusion temperature does eliminate the use of Indian coals in entrained-flow gasifiers – see section 6.4.1.

4.1.8 Ash production, storage, and utilization

Given the high ash content in Indian coals, at least one acre of land is needed for one MW of installed capacity (CEA, 2004b),[234] and hence there are many large power plants with more than 1000 acres of land dedicated simply for ash storage. Over the past decade, 1.4-1.5 million tons of ash was annually produced per GW of installed capacity (CEA, 2005e), with the number increasing slightly over time because of increasing ash content in coal and increasing PLF. The

[232] Although trace elements in Indian coals are below detectable limits, some Indian coals have higher trace elements than other coals. For example, mercury content in some Indian coals average 0.35 ppm; in comparison, the world-wide average for mercury is 0.012 ppm (Frankland, 2000). See section 3.3.3.4.
[233] The high reactivity, however, does limit the maximum temperature for gasification (Bryan et al., 2005).
[234] For example, power plants in Maharashtra require between 1.3-2.8 acres/MW. In comparison, U.K. plants typically require about 0.4 acres/MW (Dalal, 1999).

amount of ash generated in recent years is shown in Figure 33. Currently, in India, there are about 15,000 hectares of land with about 750 million tons of ash in active ash ponds.[235]

Using such large areas for ash-storage leads to air and water pollution (see sections 3.3.3 and 3.3.4) and it affects local communities, as land nearby power plants cannot be used for agricultural production, cattle grazing land, etc (NEERI, 2003). Hence, there is great interest in utilizing the fly-ash produced by power plants for productive use.

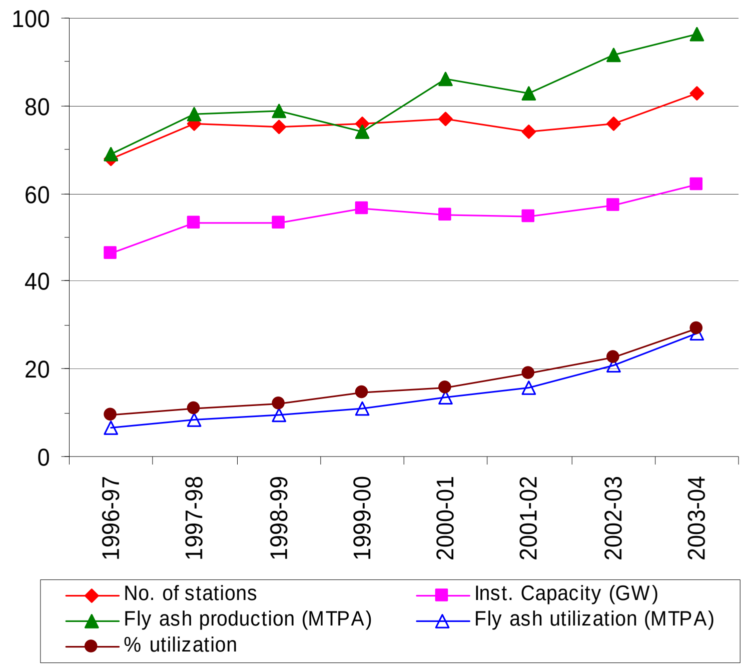

Figure 33: Fly Ash Production and Utilization. Source: (CEA, 2005e)

The ash generated by the power plants is of three kinds (Govil 1998):

- Bottom ash – ash that is settled at the bottom of the boiler, and is generally evacuated out as slurry (10-20% of total).
- Coarse fly ash – ash that is collected at the first stage of the ESP. It contains small ash chunks with carbon content around 6-7%, and is generally useful for the brick manufacturing industry (70-80% of total).[235]
- Fine fly ash – fine ash that is collected by the later ESP stages. This fine ash is either removed dry or as a slurry and put in ash yards and ponds (5-7% of total).

The ash from the power plant collected by precipitators and from the boiler is generally mixed with water and the slurry is dumped either in a temporary holding area called the "ash yard" or directly into an "ash pond", which is the main storage area for the power plant's ash. The ash in these ponds is allowed to settle and can be stored up to 90-105 feet in height.[235] After the ash pond is completely "filled", the power plant must 'reclaim' the pond by landscaping it with

[235] Interview with MoEF official (February 2005). Different sources cite a range of numbers (65,000 to 90,000 acres) for amount of land used for ash storage (see: http://www.tifac.org.in/news/flymgm.htm and http://www.worldbank.org/html/fpd/em/power/EA/india/loiat2-4.stm).

vegetation and the area becomes an inactive "ash-dump". Unfortunately, there is little uniformity of engineering design for these ash ponds, which has resulted in inefficient land-use at some power plants (NEERI, 2003). In some plants, the ash from ESP is removed dry and then either sold or given for free to brick (coarse fly ash) and cement manufacturers (fine fly ash). Dry ash removal is not used as much, although it is expected that it would become more common as fly ash begins to get utilized more in industrial processes.[236]

In order to increase fly-ash utilization, the Ministry of Environment and Forests in 1999 mandated a 100% utilization of fly ash in a phased manner by 2013-14. It has stipulated that fly ash from power plants be given free (at least until 2010)[237] to brick and cement manufacturers within 50 km radial distance from power plants; these manufacturers have also been given specific targets for ash utilization (MoEF, 1999; CEA, 2005e). It is expected that by 2010, power plants will plan on 100% utilization of the generated fly ash even prior to their commissioning, such that all generated ash would be immediately utilized.

Flyash utilization has increased ten-fold from 1992-93 to 2003-04, and about 30% of the generated ash is utilized today (see Figure 33). This dramatic improvement in fly ash utilization is primarily a result of MoEF's policies and guidance. Although much of the technology for utilizing fly ash in bricks and cement existed before the 1970s,[238] it was not deployed on a large scale. Many Indian research agencies, such as the Central Building Research Institute, Central Fuels Research Institute and Regional Research Laboratories, have been involved in developing technologies and techniques for using fly ash in industrial and agricultural processes.[235,239]

There is some concern, however, about heavy metal leaching from ash ponds, especially as many ash ponds are not lined for protection (Sushil and Batra, 2006). On the other hand, fly ash is also being considered for use in agriculture, as an ameliorant for improving crop productivity and for stabilizing degraded soils (Jala and Goya, 2006). Indeed, more studies are needed to assess the human health and safety aspects of using Indian flyash for various uses, and such studies are already underway.[240]

4.1.9 Coal Beneficiation

Given the poor quality of coal and its deleterious effects on power plants and environment, coal beneficiation (coal washing) has long been discussed as an important technological option for a long time.

Ash in Indian coals is generally finely intermixed into the coal structure and the distribution of materials across different relative density fractions is uniform. Hence, coal washing using

[236] Currently, 52 power plants report to have either dedicated dry fly-ash collection system or having the provision for dry ash collection. See: http://cpcb.nic.in//Charter/status.htm.
[237] http://www.envfor.nic.in/legis/hsm/so763(e).pdf
[238] For example, lignite-based fly ash bricks were developed and used in Neyveli by the 1980s (Interview with MoEF official, February 2005). Neyveli Lignite Corporation has been selling their flyash since the mid-60s and earning revenue (Power Economy Committee, 1973).
[239] Currently, MoEF is also negotiating changes in Indian building codes to ensure that fly-ash based cement and bricks can be legal used. Fly ash is also being used in road and bridge embankments and for dam construction.
[240] See, for example, research activities by Technology Information, Forecasting and Assessment Council (TIFAC). See: http://www.tifac.org.in/do/fly/fly.htm.

physical methods is difficult, as coal must be crushed to small sizes for effective washing. Furthermore, there is significant near gravity material at any specific gravity cut, which leads to misplacing of coal to waste, and vice-versa (Singh, 2005). The loss of coal in washery rejects can range between 8% and 15%, depending upon the nature of coal and the process of washing (Sachdev, 1998). The difficult washing characteristics tend to favor the use of dense medium separation (DMS) systems (Frankland, 2000).[241] However, the most commonly used coal washing technology in India (primarily for coking coals) is the jig washer, both of the Baum and Batac types. The Baum jigs are often used for deshaling. Greater use of DMS systems has been limited by unavailability of good quality magnetite (DTI, 2000b; Sethi, 2003). In addition, materials able to withstand the effects of fine magnetite particles are not readily available in India (DTI, 2000b).

Coal washing and beneficiation has been practiced for producing better quality coking coal for a long time. There are about 18 coking coal washeries in India (11 of them in CIL), with a total annual capacity of about 30 MT (with 2/3 of it in CIL) (Singh, 2005). However, the production from these washeries is quite poor—over the past five years, only about 5 MT of washed coal has been produced in CIL washeries (Ministry of Coal, 2006). Also, the quality of washed coking coal by CIL washeries has been inconsistent and deteriorated over time with the supply of poorer grade of raw coal (Ministry of Coal, 2006). Such underutilization has led CIL to convert some of the coking coal washeries for washing non-coking coal. Furthermore, the coking coal washeries need of modernization and most have outlived their life (V. D. Singh, 2006).

The demand for washed thermal coal has also been increasing as the quality of run-of-mine coal supplied to power plants has worsened. In 1997, the MoEF mandated the use of beneficiated coals with ash content of 34% (or lower) in power plants located beyond 1000 km from their coal source, and plants located in critically polluted areas, urban areas, and ecologically sensitive areas (CPCB, 2000b). This notification was based on a recommendation from a committee headed by the chairman of CPCB. Although this rule was to be enforced from June 2000, it is not clear how well the rule is being is met. According to the CEA, more than 40 plants (about 24 GW of capacity) needed better quality coals and the estimated annual cleaner coal consumption was expected to be about 87 MT (CPCB, 2000b). On the other hand, the thermal coal washery capacity in 1999-00 was only about 24 MT. Hence, a key option available for power plants was the use of blended coals using better quality foreign sources or a small quantity of well-cleaned domestic coal (CPCB, 2000b).

With rising demand for better quality coals, the private sector has taken an increasing interest in building washeries in the last few years. The current washery capacity is nearly 90 MT of thermal coal. The share of the private sector is about 78%, and the share of CIL (which account for about 22%) is primarily from converted-coking-coal washeries (Ministry of Coal, 2005a; Kanchan, 2006). The government has also encouraged the building of private washeries with its "build-own-and-operate (BOO)" policy. The country's first private commercial coal beneficiation plant was at Dipka in the Korba coalfield (Madhya Pradesh), owned by the Bombay Suburban Electricity Supply Company (BSES). The washery was part of an Indo-US

[241] DMS systems allow for a float/sink separation of coal from mineral matter by using a heavy liquid of appropriate density (DTI, 2001). For more details on coal washing technologies, see: (World Bank, 1997)).

Coal Preparation Programme, supported by USAID, US Asia Environmental Partnership and the Federal Energy Technology Centre (FETC) of the US DOE (Sachdev, 1998).

An important concern with increased washing in the country is the ability to deal with washery rejects. As discussed earlier, rejects have some heat value, and yet these rejects cannot be sold or traded under the current marketing regime. In 2004-05, about 2.4 MT of wastes was generated by CIL washeries and about 18 MT of waste has been accumulated up to March 2005 (Singh, 2005). Disposal of high carbon content rejects in abandoned mines could pose a hazard due to spontaneous combustion in the waste heaps (Sachdev, 1998), they can be used in washeries to generate power using fluidized bed combustion (FBC; see section 6.2). There are already small scale 5-10 MW FBC boilers in several mines, with the electricity is mainly being used inside the collieries; however, the cost of electricity generation is high—Rs. 2.5-3.5 per kWh (Singh, 2005). There are plans now for building larger FBC plants (~100 MW or higher) near washeries for utilizing washery rejects. These washery and FBC plants are also supported by BHEL.

A key constraint for a rapid build up of washery capacity is the institutional structure of the coal industry. As discussed earlier, the production, transportation and trading of coal in India is effectively controlled by the government through the Ministry of Coal. There is no effective coal market in India, as the supply of coal from the two main public sector units (CIL and SCCL) to various consumers is controlled by linkage committees (see section 4.1.5). Hence, under the current structure, coal washeries cannot get a legitimate coal linkage as an end user nor can they trade in coal. Even the washery rejects cannot be traded as they contain carbon and are classified as "coal" (Sethi, 2003).

Another constraint is the lack of contractual agreements between suppliers and consumers. Coal supply is not guaranteed at any particular quality (sizing, ash content, calorific value, etc.), and there is no penalty for non-compliance. The grading system based on UHV rather than GCV (see section 4.1.6) does not provide adequate price signals for improving coal quality. In addition, the wide bands for grades also imply that, in many cases, the washed coal may be in the same grade as the ROM coal. Coal producers in India also have not taken the responsibility of certifying quality at the consumer-end, but rather only at the supply end. The coal transporter (primarily the railways) does not take any responsibility for either the quality or quantity (Sethi, 2003).

Hence, liberalization of the coal sector and instilling contractual obligations are important elements of increasing better quality coal in India.

4.2 *Financial pressures*

Economics of power plants and the financial investments required for the growth of the power sector is an important constraint for determining coal power policies. Installation of new power plants requires an enormous financial investment – both for the initial capital expenditure during construction and for operations and maintenance throughout the plant lifetime. The Indian power sector has limited financial resources from which it can finance the construction of new infrastructure projects. At the same time, the cost of new projects in the coal-power sector has been increasing over the past several decades. The required and available financial resources, as well as the factors that affect the cost of electricity supply and generation are described below.

4.2.1 Short-term requirement

Installation of new power plants requires an enormous financial investment – both for the initial capital expenditure during construction and for operations and maintenance throughout the plant lifetime. Currently, typical total plant cost (TPC)[242] of a 500 MW coal-based power plant in India is between Rs. 30 to 40 million/MW (i.e. $0.67-0.9 million/MW),[243] with an additional 20% cost increase for financial charges and interest during construction[244]—leading to an estimated cost of more than Rs. 20 billion (~$0.44 billion) for a 500 MW power plant.

	10th Plan			11th Plan			Total
	Rs. Billion						
Resources Requirement	Central	State	Private	Central	State	Private	
Generation	1,560	560	350	1,670	640	750	5,530
Transmission	220	260	100	280	300	110	1,270
Distribution		450			500		950
Rural electrification		400			600		1,000
R & M		100			150		250
Reforms & restructuring							1,000
Total Funds Requirement	1,780	1,770	450	1,950	2,190	860	10,000

Table 22: Estimated financial requirement for the 10th and 11th five-year plans (2002-2012).
Source: (Ministry of Power, 2003)

In 2002, it was estimated that about 100 GW of new capacity would be added in the 10th and 11th five-year plans to meet the expected demand (section 3.1.2). Based on these projections, the Ministry of Power (2003) estimated that Rs. 5.5 trillion would be need for funding the 100 GW of capacity addition. Furthermore, additional resources will be required for transmission,

[242] Total plant cost (TPC) is also known as "overnight cost". About 80% of TPC is Engineering, Procurement and Construction (EPC) cost, and the rest includes taxes, duties, overhead, and land costs. TPC cost does not include financial charges or interest during construction, which is another additional 20% of TPC.
[243] Generally, it is customary to quote cost/MW using net capacity, rather than gross. However, in India, the latter is more common. The difference between the cost/MW(net) and the cost/MW(gross) is about 7-10% (depending on auxiliary consumption).
[244] CEA – Personal Communication.

distribution, R&M, rural electrification, and for completing the distribution reforms. Thus, the estimated financial requirement over the 10 year period up to 2012 was about Rs. 10 trillion (~$200 billion); see Table 22. In the coal power sector, an estimated 40-45 GW of new coal-based capacity (out of 100 GW total capacity) would require about Rs. 1.8-2.0 trillion.

Although the Ministry of Power (2003) estimated a requirement of about Rs. 3.5 trillion for the Central and State sectors in the 10th Plan (see Table 22), only Rs. 2.7 trillion was approved for the actual 10th Plan (out of which Rs. 1.8 was for capacity addition and R&M) (CEA, 2007b). Furthermore, out of the Rs. 2.7 trillion, the likely expenditure in the power sector is only Rs. 1.8 trillion—in other words, nearly 32% of the approved outlay was not spent in the 10th Plan.[245] Most of the unspent money is from the Central sector: the State sector spent nearly 97% of its outlay, whereas the Central only spent 53%. One of the primary reasons for this has been delays in approval and execution of hydroelectric and gas-based projects.

Recently, the Working Group on Power for the 11th Plan revised the estimates for funding requirements for the 11th Plan. The revised estimates are shown in Table 23. The amount of money required has nearly doubled from the initial estimate of about Rs. 5 trillion (see Table 22) to Rs. 10 trillion. About 57% of the funding is for generation capacity addition, 1.5% for R&M, 16% for transmission and 33% for distribution and rural electrification.

	Required funds in Rs. (billion)				
Category	State	Central	Private	Total	%
Generation	1,238	2,221	850	4,309	
Non-conventional and captive plants	225		930	1,155	
Merchant Plants			400	400	
Total Generation	**1,463**	**2,221**	**2,180**	**5,864**	**56.8%**
R&M	159			159	1.5%
Transmission	650	750		1,400	13.6%
Distribution + Rural electrification	2,870			2,870	27.8%
Misc.		23		23	0.2%
Total Requirement	**5,142**	**2,994**	**2,180**	**10,316**	**100.0%**

Table 23: Revised estimates for funds needed in the 11th Plan. Generation includes Rs. 2.22 trillion for 69 GW scheduled to be commissioned in the 11th Plan and Rs. 1.89 trillion allocated for construction of 92 GW of capacity that will be commissioned in the 12th Plan. It also includes outlay for distributed generation (Rs. 200 billion) development in the 11th Plan (central sector). Miscellaneous includes Rs. 4.6 billion for human resources development, Rs. 6.5 billion for demand side management and Rs. 12.1 billion for R&D. Source: (CEA, 2007b).

4.2.2 Financial resources

As shown in Figure 4, although the absolute outlay for the power sector has been increasing in the National Plans, the outlay as a fraction of total Plan allocation increased significantly during the 70s, as the central sector began to invest heavily in the power sector. In the 9th Plan, fractional outlay for the power sector decreased, as the private sector was expected to shoulder a significant has been decreasing since the mid-80s. In addition, the expenditure in power sector,

[245] Since the 1990s (8th, 9th, and 10th Plans), only about 70-75% of the outlay has been spent; see Figure 4.

which was as high as 90% of the outlay (in constant rupees) in the 1960s and 70s (2nd, 3rd, 4th and 5th Plans), has dropped to between 65-80% since the 1980s (6th, 7th, 8th, 9th and 10th Plans) – indicating that the power sector has been unable to meet the national Plan's goal of installing new capacity (see Figure 4). Constrained by the limited availability of funds, the Government opened up the power sector to private and foreign investments in the early 1990s, with the hope that these actors would play a large role in installing new capacity. However, recently, in the 10th Plan, the Government recognized that the private sector is not investing at expected rates and therefore increased the support for the power sector. Also, if the Government is to meet its growth goals, it needs to spend more. While the overall allocation for the power sector in 10th Plan was two times the expenditure in the Ninth Plan, the estimated required finances for the 11th Plan is about four times the estimated expenditure in the 10th Plan. Thus, there is an enormous financial requirement for the growing power sector.

Generally, investment outlays for public sector power projects in the national five-year plans are funded by (Jeyakumar, 2004; CEA, 2007b):

- Internal resources of the utilities
- Financing from state and central government budgets in the form of equity and loan
- Multilateral/bilateral assistance routed through government budgets
- Multilateral/bilateral loans directly to the utility
- Loans, bonds, etc. from Indian financial institutions
    - Commercial banks
    - Public financial institutions
    - Dedicated infrastructure/power finance institutions
    - Insurance companies
- Equipment supplier credit (both domestic and external)
- Credit from external credit agencies, bond markets and equity markets

For example, 19 GW of additional capacity, installed in the 9th Plan, required about Rs. 1.35 trillion. About 67% of this funding was raised from financial institutions, 11% from internal sources, 15% from budgetary support, and 7% from external assistance (Table 24).

	Central	State	Private	Total
Sources	Rs. Billion			
Internal Resources	68	18	70	155
Net Budgetary Support	144	56		200
External Assistance	15	84		99
Institutional/Banks assistance & Market borrowing	219	520	160	900
Borrowing Total	446	678	230	1354

Table 24: Financial sources for funding power sector projects of the 9th Plan.
Source: (Ministry of Power, 2003)

According to the Ministry of Power (2003), much of debt portion (70%) of the required funds for the 10th and 11th Plans can be raised through domestic (87%) and international markets (13%). Although there is no shortage of available funds in the international markets, the short-term tenure of these loans (typically just 5 years) is a problem (CEA, 2007b). Furthermore, there are additional auditing and overhead costs that comes with loans from multilateral banks such as the World Bank and the Asian Development Bank. Moreover, the power sector feels that these agencies demand a stricter accountability and compliance in environmental and social issues (CEA, 2007b). Foreign investors continue to view the Indian power projects as risky investments because of the failure of the IPP policy, the slow resolution of the Dabhol power plant disputes, the continued losses of the State Electricity Boards (and their successors), high transmission and distribution losses, etc. Hence, these investors often demand credible payment security mechanisms and credit enhancements are often provided to "comfort" the lenders (CEA, 2007b).

In addition, India does not have a large and liquid domestic debt market. The market is dominated by government securities and the corporate debt market is very small (CEA, 2007b). There are also regulatory limits on which domestic financial institutions can invest in the power sector—thereby, limiting the overall access to domestic banks and insurance companies. Two government agencies provide specific financial support for the power sector—Power Finance Corporation (PFC) and the Rural Electrification Corporation (REC)—but their funding is limited.

One of the key problems in the Indian power sector is the equity gap, particularly in the State and Private sectors (see Table 25). Equity is mainly raised through internal resources, and State and Central government support. The Central sector, which was estimated to have a gap of about 12% in the 10th Plan and 30% in the 11th Plan, can be expected to meet this gap through various means: development surcharges, partial disinvestment of central public sector units, settlement of SEB dues, etc.

	10th Plan (Ministry of Power, 2003)				11th Plan (CEA, 2007b)			
Description	State	Central	Private	Total	State	Central	Private	Total
Funds required	**1,770**	**1,780**	**450**	**4,000**	**5,142**	**2,994**	**2,180**	**10,316**
(A) EQUITY REQUIRED	531	534	135	1200	1543	898	654	3095
(B) EQUITY AVAILABLE	310	470	60	840	0	629	654	1283
(C) EQUITY GAP (A-B)	**221**	**64**	**75**	**360**	**1543**	**269**	**0**	**1811**
EQUITY GAP (%) (C/A)	*42%*	*12%*	*56%*	*30%*	*100%*	*30%*	*0%*	*59%*
(D) DEBT REQUIRED	1239	1246	315	2800	3599	2096	1526	7221
DEBT AVAILABLE								
(E) DOMESTIC	1,089	1,076	245	2,410	1,595	935	337	2,866
(F) INTERNATIONAL	150	170	70	390	55	653	143	851
(G) TOTAL DEBT (E+F)	1,239	1,246	315	2,800	1,650	1,588	479	3,717
(H) DEBT GAP(D-G)	**0**	**0**	**0**	**0**	**1949**	**508**	**1047**	**3505**
DEBT GAP (%) (H/D)	*0%*	*0%*	*0%*	*0%*	*54%*	*24%*	*69%*	*49%*

Table 25: Financial resources available for the 10th and 11th Plans. Debt and equity are based on a 70:30 debt-to-equity ratio. Note that much of the debt and equity for the 11th Plan is yet to be arranged, and hence the gap in debt and equity will be reduced. Source: (Ministry of Power, 2003) and (CEA, 2007b).

The State sector, however, faces a much more daunting task because of its poor financial condition. It is expected to have a much larger funding gap, particularly for equity. At the beginning of the 10th Plan, the State sector faced a 40% equity gap, and at the beginning of the 11th Plan, it faces 100% shortfall in equity. Most of the debt for the state sector is likely to be arranged, despite the debt-gap shown in Table 25. The primary reason for the difficulty in raising funds for the state sector is its poor financial record (see section 2.3.3). However, there are recent initiatives to bridge this gap, including increasing the debt-to-equity ratio to 80:20 and utilizing the India Power Fund (see below). In the long run, the institutional reforms, currently underway, are expected to improve the State sector's financial health.

The private sector can face further difficulties, as investors view these projects as risky investments. Nonetheless, the CEA assumes that investors will be able to raise the necessary equity from both domestic and foreign capital markets.

4.2.2.1 Power Finance Corporation (PFC)

The Government of India setup the Power Finance Corporation (PFC) in 1986 in order to help mobilize and manage domestic and international financial resources for the power sector. PFC is the leading financial institution in India for providing debt services to the power sector. As a development organization, it has primarily focused on providing grants, and interest-free loans to SEBs and State power utilities, although it does provide some support for Central utilities, private power projects, and T&D companies. Since its inception, about Rs. 300 billion (49% of its total loan sanctions) has been sanctioned for thermal power generation and R&M of thermal power station.

Since 2000, its loan sanctions and disbursements have increased at an average annual rate of about 23%.[246] It is expected that PFC will fund about 25% of total power sector investment in the 10th and 11th Plan periods, with a total disbursement of around Rs. 1600 billion during 2002-12[247] – about eight times the PFC's actual disbursement during the previous decade (PFC, 2005a).[248] The allocation of funds to State, Central and Private sector is estimated to be in the ratio of 80%, 10%, and 10%, respectively (CEA, 2007b). In addition to providing debt servicing for power plants, PFC has also recently set up a venture capital fund – India Power Fund – for providing up to 10% of equity shortfall for viable power projects. It is meant to be utilized after all other financial tie-ups in order minimize risks. PFC will market the fund to domestic financial institutions, commercial banks, and international financial institutions (Jeyakumar, 2004).

4.2.2.2 Rural Electrification Corporation

Rural Electrification Corporation (REC) was initially setup in 1969 with the main objective for financial rural electrification schemes; however, its mission was expanded in 2002 to include financial of all projects including transmission and generation without any restriction on population, geographical location or size (Ministry of Power, 2004). Under its expanded mission, REC has sanctioned 21 generation projects with an outlay of Rs. 88 billion. It is projected that REC will provide about Rs. 1000 billion (20% as working capital) during the 10th and 11th Plans (Ministry of Power, 2003). According to CEA (2007), about Rs. 590 billion is expected to be disbursed by REC in the 11th Plan, with 80% allocated for the State sector.

---

[246] In 2004-05, about loans of about Rs. 186 billion was sanctioned and Rs. 94 billion was disbursed (PFC, 2005a).
[247] About 20% of PFC's disbursement will be loans for working capital (Ministry of Power, 2003).
[248] According to CEA (2007), PFC is expected to disburse about Rs. 812 billion in the 11th Plan.

4.2.3 Cost of Electricity

The cost of electricity generation (COE) is an important economic consideration when choosing between various technologies. The financial constraints in the power sector, particularly in the SEBs, lead one to naturally consider technologies that produce electricity at low costs; hence, cost of installation (primarily capital cost) and of operations and maintenance are key constraints on new technology development and deployment. The cost of supply to consumers includes the generation cost and the cost of transmission and distribution.

As shown in Figure 10, the cost of electricity supply[249] in India has been increasing, whereas the average tariff has not kept up with this rise in cost. The average tariffs in current rupees[250] and the cost of supply have been continuously increasing since 1974-75; shown by open markers in Figure 10. However, to get a more accurate picture, it is good to compare costs and tariffs in both current and constant rupees[251] (solid markers in Figure 10). Based on constant rupee data, it is clear that the cost of supply (and tariffs) during certain time periods has been increasing much faster than inflation. The *real* cost of supply increased from 1974-75 to 1983-84 at an annual average rate of 4.4%.[252] From the 1984-85 to 1990-91, the real cost of supply remained flat, i.e., the cost of supply in current prices generally kept up with inflation, but no more. However, starting in 1992-93, the real cost of supply once again began to increase, with an average annual rate of 4.8%. In contrast, the tariffs in constant rupees, which rose slightly at an annual rate of 4% from 1974-75 to 1982-83, stagnated at around Rs. 2.0/kWh[253] until 1995-96, leading to a large gap between cost of supply and average tariffs. Since 1995-96, tariffs have been increasing at an annual rate of 4% – although slower than the 4.4% rise in cost of supply. The gap between cost of supply and average tariffs has therefore continued to widen – in 2001-02, the recovery was below 70% (see Figure 10).

The recent increase in the cost of supply is mainly due to increases in power purchase charges, as shown in Figure 34. The power purchase charges include the amount paid by SEBs for purchasing power from centrally owned utilities, such as NTPC and DVB, private generators, IPPs and from neighboring states.[254] As power consumption rose in the country, SEBs began to purchase more power at higher costs from central utilities. Some of this rise in cost may be accounted by structural changes in the technologies used for electricity generation during this period – for example, natural gas-based capacity increased more than four-fold from 1991-92 to 2001-02 (see Figure 2) – and by increases in project costs (see below). Thus, the cost to SEBs for purchasing power increased from about 28% in 1992-93 to about 53% of the total supply cost in 2001-02, (see Figure 34).

[249] Based on publicly available data, it is difficult to ascertain the cost of generation by itself.
[250] The tariff in current rupees is what the consumer actually pays.
[251] The conversion from current to constant rupees is based on GDP deflators.
[252] In current rupees, the annual rise in cost of supply is about 11.5%.
[253] In current rupees, the tariff in this period increased at an annual rate of 9% -- same as the inflation rate.
[254] The fraction of the central utilities in the total power purchase has reduced to 57% in 2001-02 from 77% in 1992-93, because, more recently, a greater amount of power is being purchased from private generators and unbundled state utilities. Nonetheless, the overall power purchase has increased from 107 TWh to 320 TWh in the same period. By 2001-02, about 37% of the net available electricity at the SEB bus bars was purchased from central utilities, in comparison to 30% in 1992-93 (Planning Commission, 2001, 2002a).

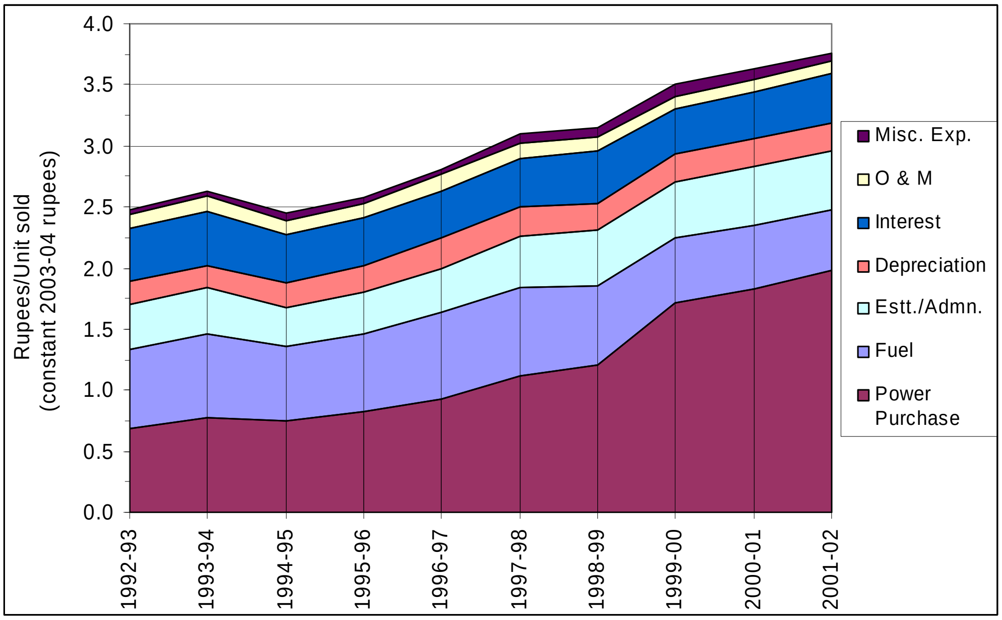

Figure 34: Breakdown of SEB cost of supply. The various components of the cost of supply (in real 2003-04 rupees) are shown from 1992-2002. The price/unit sold includes both generation costs and transmission & distribution costs. Note that fuel costs/*unit sold*, as shown in the figure, will be less than the fuel cost/*unit self-generated* by SEBs, because 'units sold' includes both 'units self generated' by SEBs and 'units purchased' by SEBs. Source: (Planning Commission, 1999, 2002a); revised estimates used for 2000-2001; estimates from the Annual Plan used for 2001-02.

	Fuel Cost		Fuel Cost per kWh	
	Coal Rs./kg	Oil Rs./liter	Coal (paise/kWh)	Oil (paise/kWh)
	in constant 2003-04 rupees			
1992-93	1.37	9.1	103.1	7.14
1993-94	1.47	11.0	113.1	6.16
1994-95	1.39	9.7	107.2	6.44
1995-96	1.36	9.3	103.5	10.04
1996-97	1.49	10.5	113.4	5.77
1997-98	1.56	11.4	118.6	4.77
1998-99	1.50	9.5	112.3	4.06
1999-00	1.47	10.8	108.8	4.02
2000-01 (RE)	1.46	13.7	111.3	4.77
2001-02 (AP)	1.53	14.3	113.2	5.15

Table 26: Fuel Costs in SEB thermal power plants. These costs are only for SEB owned power plants and do not include private and central utilities. Data for 2000-01 are revised estimates and for 2001-02 is from the Annual Plan. The cost is converted from current rupees to constant 2003-04 rupees using GDP deflators; over this 10 year period, the average rate of annual inflation was about 6%. Source: (Planning Commission, 2002a).

Fuel costs (particularly of coal) did not play much of role in increasing the price of supplied power, primarily because cost of the fuel supplied to SEB-owned thermal power stations increased at average annual rate of only 1% in constant rupees (8% in current rupees); see Table 26. At the same time, the specific consumption of coal stayed relatively constant (it has averaged about 0.76 kg/kWh), while the specific oil consumption has decreased from about 8-10 ml/kWh in the early 1990s to about 3-4 ml/kWh by turn of the century.

4.2.4 Project Costs

In contrast to fuel costs, the cost of installing coal-based power plants in India has been slowly increasing from the early 1970s to present. The project costs[255] can be obtained from the CEA's techno-economic clearance (TEC), which had been a statutory requirement for thermal power projects until recently. The executing SEBs/central utilities would submit the project proposal to the CEA, which would then assess the project on its technical and economical merits. At the TEC stage, the project costs are estimated based on prevailing cost/price structure for the power plants. The actual costs have generally been higher than initial estimates. The initial costs inevitably vary due to many factors including the size of power plants, whether the project is a green-field or brown-field[256], site-specific technical needs, cost and quality of coal (which varies depending on transportation costs), etc. (Govil, 1998).

Govil (1998) has tabulated the estimated costs from the CEA's feasibility reports for coal power plants over a 30-year time period.[257] The averages of estimated project costs (in constant 2003-04 rupees) as a function of the calendar year of CEA approval are shown in Figure 35 (diamonds). As the data indicates, the approved project costs for the first power plants (1966 – 1974) built by BHEL showed a decreasing trend in cost. Govil has explained this decreasing trend by the fact that these first power plants were manufactured using technologies from initial collaborations in the 1960s, and were designed around in-house technical capabilities (Govil, 1998). Starting from mid-1970s to the late-1980s, the real costs of coal power projects nearly doubled – from about Rs. 15-20 million/MW to about Rs. 30-35 million/MW (in constant 2003-04 rupees) – with the real costs growing at an annual rate of about 4% per year. The breakup of the total project cost into various categories such as capital, financing, construction, etc. is generally not available or easy to obtain, and hence it is not clear to the exact reasons for why the projects have increased so much. However, according to Govil, some of reasons for the increase in cost include a preference for acquiring of new technologies through foreign collaborations (see section 2.3.2), inability for BHEL to utilize its in-house design capabilities and manufacture new products based on problem-solving innovations, monopoly status enjoyed by BHEL, lack of domestic competition for power plant equipment, rise in the cost of steel, rise in the increased use of expensive imported steel in the formed sections, higher input of foreign technology/material content and foreign know-how, etc. (Govil, 1998).[258] Furthermore, the monopoly status enjoyed by BHEL implied that the price of power equipment was determined

---

[255] The project costs generally includes the overnight total plant cost (equipment costs, buildings, site preparation, etc.), owner's cost including spare parts, startup costs, and land costs, interest during construction, taxes, and other contingency fees.

[256] Greenfield projects are brand-new power projects where there are no existing infrastructure to build upon. Brownfield projects are those where older existing units are retrofitted or additional units are added to existing power plants. Generally, Greenfield projects are more expensive than Brownfield ones.

[257] Govil has tabulated year-wise CEA cost data into five categories based on size of the thermal units or the MW rating of the project, i.e., a project size of 120 MW could include two 60 MW units (Govil 1998: Table 8.7). This data shown here is an average of these five categories.

[258] Interestingly, the problems regarding foreign components and rise in costs were important during the pre-Independence period to nationalize the electricity manufacturing sector. However, nationalization did not eliminate the problem at all, and it perhaps made it worse.

solely by BHEL and administered by Ministry of Power. BHEL's supply of total main plant with lump-sum price rather than quoting for individual parts was also a disincentive a better techno-economic analysis (Govil, 1998).

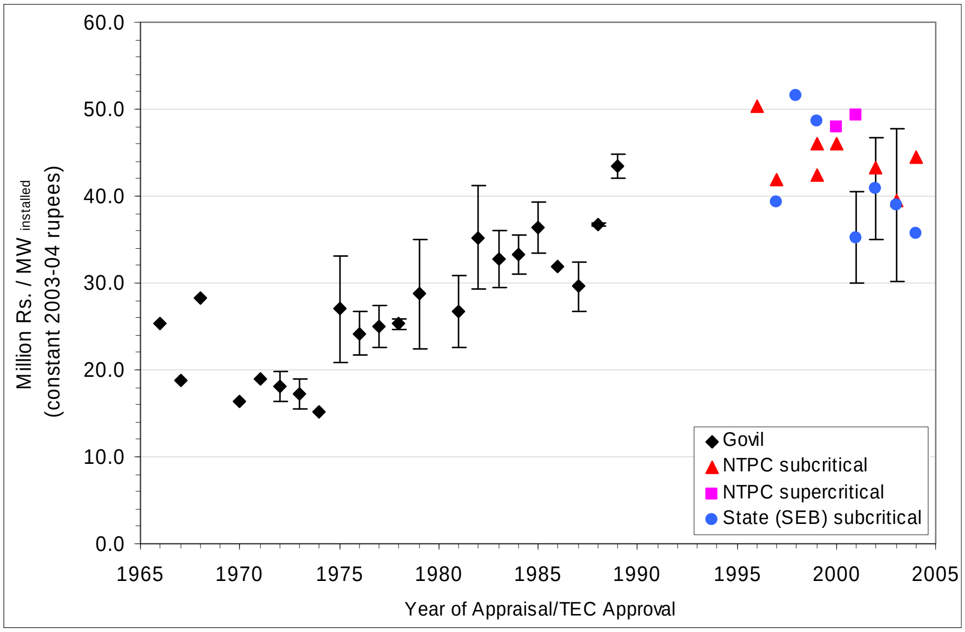

Figure 35: Cost of coal power projects. The estimated project costs per MW of installation at the time of CEA appraisal or techno-economic clearance are shown for each calendar year. Cost estimates from Table 8.7 of (Govil, 1998) were averaged over various categories of project sizes; the range bars indicate the standard deviation for these averages. The estimates were converted to constant 2003-04 rupees using GDP deflators. Estimated cost/MW installed[259] of NTPC projects in the 10th Plan approved by the CEA (techno-economic clearance) using subcritical and supercritical PC technologies are shown. Estimated average costs of State/SEB approved projects are also shown; the error bars indicate the standard deviation for these averages. Source: (CEA, 2005a).

Current project costs for sub-critical PC range between Rs. 30-50 million/MW (in 2003-04 rupees) depending on various site-specific characteristics. CEA appraisal costs for NTPC and SEB power projects in the 10th Plan are also shown in Figure 35. According to their TECs, the two supercritical PC power plants of NTPC have project costs of Rs. 48 and 49 million/$MW_{installed}$ (2003-04 rupees) for Sipat and Barh, respectively. The Nexant (2003) study has estimated that the total plant cost for a 500 MW subcritical power plant using run-of-mine coal is about Rs. 26 million/MW_{net} (\$576/kW_{net})[260], with the total project cost (including IDC) of about Rs. 42 million/MW_{net} (\$873/kW_{net}).[260]

Thus, it is evident that real cost of coal projects has not decreased, *but increased*, over the past three decades even though the basic technology has not changed much—the project costs (in real rupee terms) have almost doubled from the mid-1970s to late-1980s, although the cumulative additions of coal-based capacity quadrupled during this period. Assuming that the changes in project costs is determined mainly by increases in total plant cost (as opposed to changes in interest rates or other fees), this increase in appears to contradict the general view of reduction in costs that occurs when more capacity is added – i.e., the concept of "learning by doing".

[259] Note that cost/installed MW will be lower than cost/net MW. Generally, it is better to use cost/net MW since a more relevant parameter for a power plant is net output, rather than gross output.
[260] Mid-2002 pricing; assuming an exchange rate of Rs. 48.5 / \$1.

4.3 Technological capacity

Technological capacity in developing countries is a well-researched subject (see, for example: (Katz, 1984; Lall, 1987). It can be broadly defined as the technical, managerial and organizational skills that are necessary for industrial enterprises to set up industries based on given technologies (regardless of their source), utilize them efficiently, improve and expand them, and develop new products and processes over time (Najmabadi and Lall, 1995). Technological capacity is not generated by simply producing more engineers and scientists, nor is it gained by some automatic learning-by-doing, but rather it derives mainly from learning, which is based partly on production experience, import of knowledge and technologies from foreign sources, and from deliberate process of investment in indigenous creation of knowledge and skills (Lall, 1987).

Increasing technological capacity in various sectors was on the forefront of Indian industrial policies after independence. The Industrial Policy Resolutions of 1948 and 1956 recognized the importance of industrial production and emphasized the role of the State in key areas necessary for India's development.[261] The Government played a direct role in increasing capacity by setting up new enterprises in specific areas, including the power sector. It also guided and regulated industrial production more generally. Subsequent policy statements such as the Scientific Policy Resolution of 1958 reaffirmed the primacy of science and technology for national prosperity and emphasized the need for educating and training a suitable cadre of scientific personnel.[262] As a result, the Government set up a national network of education, training, and research institutions to build up the scientific manpower in India, which has now led to India having the world's third largest pool of scientific personnel. The government also established the Council for Scientific and Industrial Research (CSIR), a network of national laboratories that cover a whole gamut of scientific and technical areas. However, the science and technology infrastructure has been largely delinked from the industries, and although industries do have contacts with CSIR laboratories, they do not necessarily rely on CSIR-developed technologies (Lall, 1987).

Since self-reliance was one of the key tenets of the country's developmental philosophy, there was a significant emphasis on not just utilizing foreign technologies but also on building up domestic manufacturing base and developing indigenous technologies[263] – import-substitution was a key element in the Indian industrial and trade polices. This allowed India to become one of the few developing countries to have strong industrial manufacturing base in a number of sectors, including the power sector. Yet, progress on indigenous technology development has been spotty. The country has made great progress in areas such as space and nuclear power, where India has the capacity to launch its own satellites and install indigenous nuclear power plants. Other areas, though, such as the automobile and power sector, have shown much less technological dynamism – in the automobile sector, for example, until recently the production was dominated by "hand-me-down" models from industrialized countries (Sagar and Chandra, 2004). Similarly, all of the power plants in the country are either fully imported or based on licensed technologies that are manufactured in the country.

---

[261] See: http://www.laghu-udyog.com/policies/iip.htm.
[262] See: http://nrdms.gov.in/sci_policy.asp.
[263] Although sometimes 'technological self-reliance' appears to be a end in itself in India (Lall, 1987).

Although there are many elements of technological capacity and many ways of dividing the various constituents,[264] we have divided our discussion here into three broad categories, as relevant for the coal-power sector: capacity for innovation (technological progress), capacity of manufacturing, and capacity in utilities/generation companies to operate and maintain power plants.

4.3.1 Innovation Capacity

India has built up significant technological capabilities (especially in comparison to most other developing countries) in the years since independence. This includes capacity in complex industrial manufacturing, adoption of technologies, and even innovation in many areas (especially chemicals, and more recently, pharmaceuticals and information technology). Yet the country's innovative capacity remains largely unrealized, and the country's innovation system is relatively small, largely fragmented, and performs well only in a few sectors.

The overall level of R&D effort in the country remains relatively limited in absolute and relative terms: in 2004-05, the national expenditure on R&D was Rs. 216.4 billion, which was about 0.77% of the GDP (DST, 2005). This translates to about $4.82 billion in market-exchange-rate terms and PPP$44.1 billion in purchasing-power-parity terms.[265] The United States, in comparison, is estimated to have spent $312.1 billion on R&D in 2004, which was about 2.7% of the national GDP (NSB, 2006). Thus, not only does India spend far less than the United States on R&D (which is not surprising), but it spends much less as a fraction of the GDP. In fact, in 2002, the overall R&D intensity across OECD countries was 2.26%; even China spent 1.22% of its GDP on R&D in that year (NSB, 2006). Furthermore, Indian R&D is mainly dominated by government funds – central and state governments accounted for about 70% of the R&D expenditures, while industry contributed only about 20% in 2002-03 (DST, 2005); in comparison, in the United States, government contributed 30 % and industry 64% in 2004, and across all OECD countries, governments contributed only 30% of the total R&D funds in 2002 (NSB, 2006).

The innovation system in India is also fragmented—there are only limited interactions between academia, industrial labs and government laboratories. In fact, government institutions are also the main performers of R&D, which is contrast to most industrialized countries where the private sector is the main performer of R&D – in the United States, for example, private industry performs about 70% of the total R&D. One peculiarity in India is that most of large industries with R&D are also government owned, and most of the industrial R&D is done in these public sector industries. The Indian academia is generally characterized by a lack of emphasis on industrial research, and as mentioned earlier the vast government-supported science and technology infrastructure (CSIR laboratories, etc.) has not provided much benefit to technology development and use in industry[266] (although the government has recently been taking steps to correct this situation and promote connections between academic and government labs and industry). Thus, there is little concerted effort to coordinate the development of new

[264] For example, Lall (1987) divides the setting up and functioning of a manufacturing activity into five elements: pre-investment choice, project execution, plant operation, technological improvement, and technology transfer.
[265] Exchange rates are derived from *World Development Indicators* (World Bank, 2005).
[266] See, for example: (Desai, 1980) and (Lall, 1987).

technologies, and hence R&D efforts are often not synergistic. Innovation of new technologies requires strategic, constant interactions between academic researchers, R&D labs, and industries (manufacturers and utilities) – what is referred to as the 'Golden Triangle' by Roy (2004).

There is also very little focus within the country on strategic planning for technology innovation, particularly in the power sector. For example, in the renewables area, the government has funded research, development, and demonstration/deployment programs in an enormous number of areas and applications. In the thermal power sector, there has been (and continues to be) a significant push on developing and demonstrating IGCC but not as much on other advanced technologies, such as supercritical or ultra-supercritical PC technologies.

Furthermore, as Govil (1998) points out, the model of self-reliance in post-independent India was based on an imported concept of development, which led to self-reliance in manufacturing goods and machinery (i.e. import-substitution) rather than in strengthening indigenous talent and institutions with local resources. The heavy reliance on foreign technology and capital, and the use of foreign experts to study Indian problems might have prevented the build-up of indigenous technological capacity to solve Indian problems (Govil, 1998). While foreign technologies can supplement the technology base, successful adaptation of foreign technologies requires significant indigenous development effort (Katz, 1984). While he ability to manufacture technologies based on slightly modified foreign blue-prints may be considered as 'know-how', designs for new products requires the 'know-why' – knowledge and understanding of basic principles underlying a technology. Innovation, which is enhancing the 'know-why' – demands continued build-up of technological capacity, which requires much more institutional and financial support (Lall, 1987).

4.3.1.1 Innovation in Indian coal power sector

Energy R&D represents an important category in the overall Indian Government's R&D expenditure – in 1996-97, the government spent 7.6% of its total R&D budget on energy research. In comparison, U.S. spends about 3-4% and the Japan spends about 20% of its R&D budget for energy research (Sagar, 2002). However, the R&D expenditure for the coal-based power sector is quite meager, and it indicates a serious constraint for developing indigenous coal power technologies.

R&D in the Indian coal power sector is dominated by public sector institutions, led by BHEL, Central Power Research Institute (CPRI), CSIR laboratories such as the Central Fuel Research Institute (CFRI) and Indian Institute of Chemical Technology (IICT) and more recently, NTPC's Energy Technologies division. A few academic institutions such as the Indian Institutes of Technology do have research activities in this area, but by and large they are minor players in the overall R&D landscape. NTPC's Energy Technologies is, however, attempting to engage more with academic institutions in enhancing their technology R&D.[267]

BHEL, India's main energy-technology company, has a robust (by Indian standards) R&D program: In 2004-05, it spent Rs. 1.25 billion (i.e., $27.9 million in market-exchange rate terms

[267] Interview with NPTC officials (February 2005).

or $255 million in purchasing-power-parity terms) on R&D.[268] However, it is also notable that BHEL's R&D effort supports 180 products across 30 categories, and therefore, its R&D for coal power development is only a fraction of the total R&D. Its most important R&D achievement seems to be the development of the fluidized bed boiler, which has now been commercialized (Lall, 1987). Although there have been significant RD^2 efforts for developing IGCC technology, based on fluidized bed gasifer, the technology is not commercialized (see section 6.4.2). Overall, products developed in-house during the previous five years have contributed about 7% to the revenues in 2005-06.[269] India's largest utility, NTPC, spent only 0.01% of its turnover (Rs. 180 million; 0.5% of net profit) for R&D during 2002-03 (NTPC, 2003), although NTPC's R&D expenditure is expected to rise to Rs. 350-400 million over the next few years.[267] Furthermore, given that the NTPC research efforts are still at a very early stage, it might take several years before they begin to substantially contribute to power sector innovation.

In comparison, Siemens, a major international energy-technology firm, spent €2.49 billion on power, lighting, automation & control as well as transportation related R&D in 2004, of which the power division accounted for €423 million (i.e., $525 million in market-exchange rate terms (1€= 1.24US$) or $448 million in purchasing-power-parity terms (1€=1.06PPP$) with significant additional expenditures on automation and control as well as transportation (Siemens, 2005).[265] In 2004, its power R&D expenditure was 3.8% of sales; the corresponding number for BHEL (i.e., overall R&D as a percentage of total sales) is 1.2%. Another major global technology developer for the power sector, Alstom, had an overall R&D expenditure of €336 million in 2004-05 (i.e., $417 million in market-exchange rate terms (1€= 1.24US$) or $356 million in purchasing-power-parity terms (1€=1.06PPP$), which was 2.5% of its total turnover (Alstom, 2005a).

In addition, many of the R&D projects in the coal power sector have been relying on foreign sources of funding. For example, the establishment of CPRI was catalyzed by UNDP funds (Govil, 1998). The BHEL R&D facilities were supported technically and financially by U.S. AID funds. U.S. AID is also supporting CENPEEP[270] (which is housed within NTPC) to improve the efficiency of Indian power plants and the recent feasibility study of assessing technologies for IGCC in India. Such studies typically use foreign consultants, which eliminate opportunities for Indian consultants and researchers to engage in such analyses, which would increase their capabilities.

Thus, the innovation system for coal power sector in India requires an infusion of significant domestic financial resources and institutional changes in order to successfully develop new technologies and compete with other international firms.

---

[268] In 2006-07, it is expected to increase the R&D funding substantially to about Rs. 2 billion. See: http://news.oneindia.in/2006/04/12/bhel-plans-rs-200-cr-rd-fund-1144843530.html

[269] http://www.bhel.com/bhel/about_rd.htm.

[270] As discussed earlier, Centre for Power Efficiency & Environmental Protection (CenPEEP) is a NTPC-USAID collaboration that acts as a resource center for acquiring, demonstrating and disseminating technologies and practices for reducing greenhouse gas emissions from power plants.

4.3.2 Technical capacity for manufacturing

The manufacturing base in India's power sector is dominated by public sector units such as BHEL and IL, as a result of India's initial industrial policies. The creation of BHEL consolidated the power plant manufacturing capacity in the country, and BHEL continues to be the dominant technology supplier for power plants in the country (see Figure 8). As of 2003, nearly 80% of installed thermal capacity in India (50.4 GW out of 62.7 GW) had been manufactured by BHEL (CEA, 2004b), thereby revealing the deep manufacturing capacity in the country. However, as discussed earlier, much of BHEL's manufacturing capacity has been geared for replication of licensed foreign technologies, rather than for increasing innovation.

It is expected that BHEL will be able to manufacture new advanced power plants, as long as materials, designs, and relevant technical know-how is transferred to BHEL. Hence, technical capacity for manufacturing is not lacking in the country.

4.3.3 Capacity for operations and maintenance

Operations and maintenance (O&M) of power plants is crucial for ensuring successful operation of power plants. India's existing capacity for O&M is varied – with very good capacity in utilities such as NTPC and a few SEBs, whereas many of the SEBs in the country lack sufficiently trained operators who can run power plants on a regular basis. One metric of assessing the capacity for O&M is the overall availability of the operating plants. Although, availability can vary for various reasons, Govil (1998) has shown that availability is more a function of a utility's capacity for managing and operating the plant than coal quality.

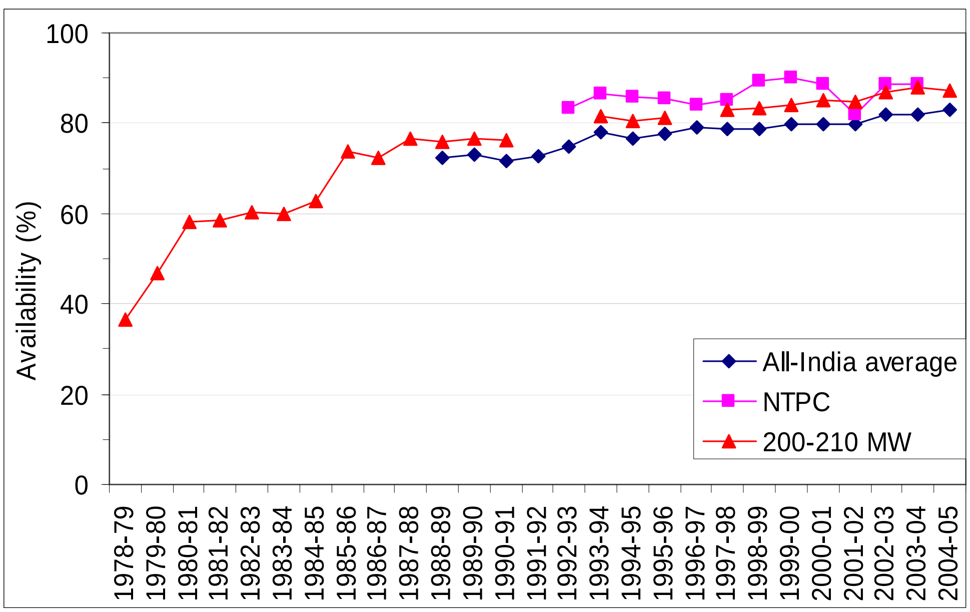

Figure 36: Operating availability of power plants. Availability of power plants from 1979 to present is shown for 200/210 MW units (triangles), all NTPC plants (squares) and average of all coal power plant units (diamonds). Source: NTPC website, CEA TPS Performance Reviews 1995-96, 1999-00, 2002-03 and 2004-05, Govil 1998.

The availability of coal-based power plants with 200/210 MW units (shown as solid triangles), of NTPC plants (1992-2004 data shown as solid squares) and of the whole country (1990-2004 data shown as solid diamonds) is shown in Figure 36. As shown in Figure 8, 200/210 MW units were installed in great numbers in the 1980s, and the increase in availability of these units over the decades indicates the increase in operating capabilities of engineers in these power plants. Initially, the capacity of the engineers to solve the initial teething problems with these units was quite low, but with more experience and input from CEA engineers, the capabilities of power plants engineers increased (see section 2.3.2). In addition, NTPC's capacity in power plant operations is often superior to many SEBs, as indicated by the higher availability in NTPC plants than the average of all power plants in the country. However, it must be noted that operational capacity within SEBs is quite varied; with some SEB plants having better availability than NTPC plants in some years (see Figure 37). For example, better-performing plants in SEBs, such as those in Andhra Pradesh, Karnataka and Maharashtra, have availabilities better than 80%, similar to NTPC-operated plants. On the other hand, poorly-performing plants in Bihar, Uttar Pradesh and West Bengal, have low availabilities.

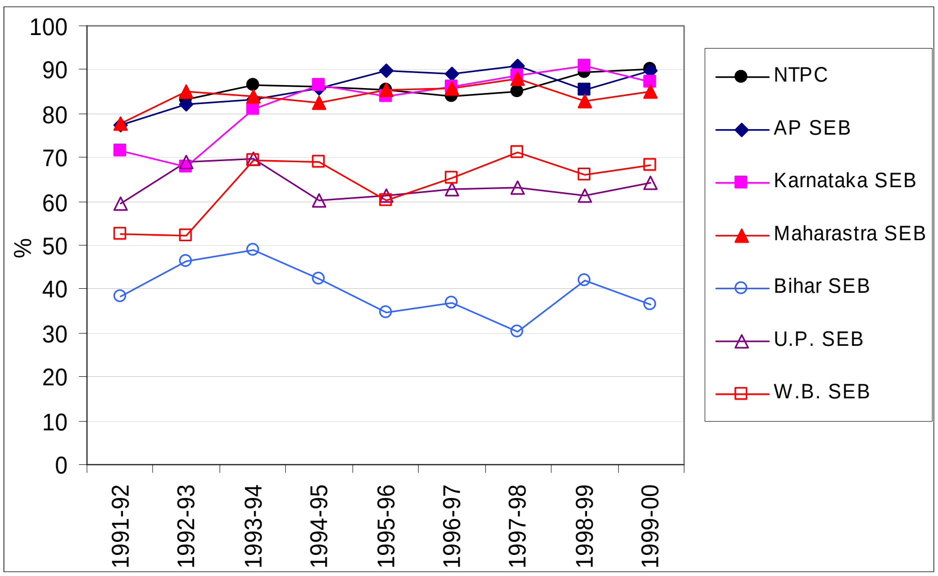

Figure 37: Availability of SEB-owned thermal power plants. Source: NTPC website and (CMIE, 1999, 2002).

Another important indicator of technical capacity for power plant operations is the level of technical consulting between power plant operators. NTPC has a well-established history and capacity for taking over poorly performing state-owned power plants, and successfully turning them around to better performance over a short period of time. In addition, NTPC also has a consultancy wing that provides power plant management and operating skills for state-owned power plants.

Finally, there are also linkages between Indian power plant engineers and their counterparts in United States through the CENPEEP program. CENPEEP has provided opportunities for NTPC to learn from techniques used in the U.S. power plants for improving efficiency and reducing emissions. The techniques and lessons-learned from such international programs be transferred to power plant operations across the country, especially since NTPC already has a significant level of technical capacity, in contrast to the capacity at the state level.

4.3.4 Constraints for future technology

Indigenous technology development requires not only significant investments in R&D, but also appropriate design of R&D programs. R&D efforts must be focused with interactions between current plant engineers and researchers involved in technology development. Currently, R&D investment for new coal technologies in the country is quite low, as indicated by the meager R&D expenditure at BHEL, CSIR and NTPC. Although R&D efforts are being increased, this could be a serious constraint for indigenous technology development.

As discussed in section 2.3.2, some of the large-scale technology development and designs (for example, the development of indigenous 500 MW units) have been side-stepped in favor of foreign technologies (Govil, 1998). Initially, the government's push for rapid capacity growth had to be met by importing entire power plants and early indigenous manufacturing had to collaborate with foreign technology developers in order to quickly gain the technical skills and capabilities necessary for manufacturing power plants. While indigenous technology development could have developed further, the lack of competition in power plant manufacturing combined with the easy access for foreign collaborations under the government policies has led to the current situation.[271] With the singular exception of CFBC boilers, BHEL does not appear to have the capability to develop and commercialize new generation of coal-power technologies on its own (Lall, 1987). In effect, it was 'self-reliance' and 'indigenization' only in name – mainly aimed only at manufacturing, and not for knowledge creation, innovation, or a holistic development of power plant technologies.[272] Technology development and their deployment require commitment to new technologies at both the engineering/R&D level and, more importantly, at the management level. In contrast to the power sector, India has had such strong support and commitment at all levels in the nuclear power and space industries, albeit mainly because of external forces.[273]

Furthermore, indigenous technical capacity might become limited in the future, as technology deployment might be driven more by market pressures than by notions of self-reliance, as in the past. Technologies chosen by the market generally favor commercial technologies with minimal capital investment,[274] without much regard for the buildup of indigenous technology innovation capacity.

Thus, a key constraint for the development and deployment of new technologies in India is the low level of technology innovation capacity, particularly in R&D effort – both in terms of expenditure and institutional support.

[271] See chapters 6 and 7 of Govil 1998.
[272] Technology innovation capacity should also incorporate the lessons learned from operation and maintenance of power plants.
[273] Since India's nuclear explosion in 1974, the country has been banned from getting access to international nuclear technology, nuclear fuel, and space/missile technologies.
[274] For example, the rapid development of NGCC in India is largely market-driven, despite supply problems in some cases.

4.4 Institutional issues

An understanding of the institutional issues is crucial for assessing barriers for technology deployment. The technological trajectory of the Indian power sector has been shaped, in many ways, by institutions such as the Planning Commission, the Ministry of Power, CEA, BHEL, and NTPC. These institutions and their policies play a central role in shaping the environment for developing and deploying new technologies. Given that continuous adaptation to changing and technological circumstances is a precondition to sustained development (Cortright, 2001), it is crucial for the sustained health of the Indian power sector to examine and, as and when necessary, reshape these institutions and mode of operations within key organizations.

4.4.1 Panic mode of operations

India has historically had a shortage of power, partly due to increasing demand as a result of population and economic growth and partly due to lack of sufficient capacity additions. At the same time, plans drawn up by the Planning Commission and the Ministry of Power have often overestimated the institutional potential for short-term capacity additions, resulting in less capacity being actually installed.[275] This has been particularly noticeable in the post-liberalization era, when the urgent need for immense capacity additions has been given much prominence and often used as a justification for drastic policy reforms.[276] Unfortunately, the presentation of such urgency puts undue emphasis on the immediate and short-term needs and effectively impedes the development of a suitable long-term strategy. A good example of this is the 1991 IPP policy that was singularly unsuccessful in adding significant capacity and had no strategic impact on fuel choices and/or on new technologies (see section 2.4.1).

4.4.2 Narrow focus and risk aversion

Linked to (and often driven by) the above-mentioned "panic-mode" of operations is the undue focus on generation, rather than on the power sector as a whole. Estimates of transmission and distribution losses routinely suggest that these are higher than those in most other countries, and hence many experts have advocated for investments in T&D to be comparable to that in generation (see, for example, Roy (1999)). However, even in the Ninth plan, the T&D outlay was only about two-third of the generation outlay. Outlays for R&M still remain woefully low, despite the enormous potential for efficiency improvement in many power plants—these plants could also make better use of existing technologies.

The lack of a clear strategic vision combined with the urgency to install new capacity leads to risk aversion. Thus, there is an emphasis on deploying tested (but older) technologies, which offer a significant cost advantage and lower technological/operational uncertainties. However, the use of these older technologies can be inefficient and therefore questionable from a long-term

---

[275] For example, during the Ninth Plan, 19,015 MW of capacity was added, which was 47 per cent of the targeted addition of 40,245 MW. Similarly, capacity addition during the Eighth Plan was 54 per cent of the target (16,422 MW against the target of 30,538 MW) (Tenth Plan, Ch. 8.2). The mid-term review of the Tenth Plan indicated that 12,204 MW of capacity was added/anticipated in the first three years of the plan (Mid -Term Appraisal of the Tenth Five Year Plan (2002-2007), Ch. 10). Given that the five-year target for this plan is 41,110 MW, it is clear that there will be again a shortfall, the only question being its extent.

[276] See, for example, "Fueling India's growth and development: World Bank Support for India's Energy Sector," World Bank, 1999.

perspective. Moreover, state utilities are more reluctant to take on additional technology risks, and there is a tendency to rely on NTPC for 'testing' new technologies before attempting to implement them at the state level. Similarly, on the manufacturing front, in the absence of local competition, there has been little impetus for BHEL to develop or manufacture more advanced technologies that are at par with what's being used in industrialized countries or even newly-industrialized countries such as Korea. BHEL technologies have, nonetheless, continued to be deployed in India and have, in fact, dominated the market—over 90,000 MW of power generation for utilities, captive and industrial plants use BHEL technologies.[277] As of March 2005, BHEL thermal sets accounted for 65% of the total thermal power generation capacity of the country (BHEL, 2005a).

4.4.3 Culture and legacy of state domination

The culture and legacy of state domination has had some unfortunate implications for the power sector, both in manufacturing and in utilities. Direct influence of the State over both the administration of relevant organizations as well as the policy context in which they operate has strongly affected the power sector.

Traditionally, the governance and functioning of PSUs has been virtually completely controlled by administrative departments in the concerned ministries. The government as the majority shareholder takes decisions regarding senior management through the concerned ministry with the help of the Public Enterprises Selection Board (Varma, 1997). Also, the application of a bureaucratic approach to appointments results in senior management personnel staying in their jobs for only a few years—therefore, they are unlikely to be able to develop and implement long-term visions without longer tenures.

The key PSUs in the power sector, BHEL and NTPC, are very much influenced by government policies and bureaucracy. Even though BHEL is regarded as a Navaratna, one of the nine 'star PSUs' with relatively greater autonomy, it is not impervious to government influence. Similarly NTPC, which has mostly been shielded from political vagaries, sometimes comes under political pressure to make decisions that may not necessarily in full alignment with its corporate strategy.[278] Furthermore, the government's initial perspective on industrial development (as documented in the Industrial Policy Resolutions of 1948 and 1956) have resulted in the state having a virtual monopoly over manufacturing of heavy electrical equipment as well as over power plant utilities in the country. In the case of BHEL, this policy agenda cut both ways: while access to the large Indian market allowed the firm to strengthen its manufacturing capabilities, the lack of competition also meant that there was not much incentive for technological innovation. In a related vein, even though NTPC and BHEL should have been natural strategic partners – leveraging the potential synergy between them could greatly advance technology development and deployment in the country – this has not really happened.

At the same time, the state influence over SEBs has been even greater (as discussed in section 2.3.3). In theory, the SEBs are quasi-autonomous bodies, with the state (and, to some extent, central) governments setting appropriate policies for the power sector. However, in practice, the government apparatus in states exercises control not just over policies but also over

[277] See: http://www.bhel.com/bhel/about.htm.
[278] Interview with NTPC officials (February 2005).

administrative, financial, and technical aspects of the SEB functioning (including critical matters such as tariff setting, investments and loans, writing-off of dues, transfer of officers, etc.). These decisions are often driven by political considerations and end up sacrificing the long term interests of the SEB and of the state power sector (Wagle et al., 1998). This has led to politically expedient but pernicious decisions such as the heavy subsidization of the agricultural sector (through flat or no tariffs), forcing the SEBs to be perpetually in a financially precarious position. This also leaves little resources (and incentives) for the managers or workers to substantially improve the performance of power plants and to take a forward-looking view, in terms of new technologies, let alone engage in R&D activities, in contrast to major utilities in other parts of the world.[279] The SEBs' monopolistic position in terms of local transmission and distribution also gave them no impetus to upgrade distribution infrastructure.

4.4.4 Lack of domestic policy-research capacity

The limited attention paid to policy research and analysis in the country has greatly impeded the development of a domestically-led coherent, long-term policy and its strategic implementation. Indian government institutions, such as the Planning Commission and the Power Ministry, rarely prepare for public comment white papers that discuss significant policy issues and possible approaches towards them.[280] In part, this is due the limited nature of policy-related analytical capacity available in these institutions; and even in cases where they may be relevant expertise in the government, the enormous and varied workload precludes the possibility of devoting sustained attention to long-term issues. Furthermore, it is essential that the government submit its policies and policy-making processes to external scrutiny, lest the "looming problems go undetected, while alternatives for tackling them ignored."[281] Currently, the government generally prefers the mode of 'expert committees' to determine new policy issues, including technology policies. While this seems most reasonable,[282] i.e., to get the 'experts' to make decisions on detailed technical issues, it can become quite technocratic. Technology decision making must include not just experts from the government and industry, but a wider set of stakeholders including academics, NGOs, etc. (see section 5.2 for more discussion).

Academics have paid only limited attention to power-sector policies (and to the extent they have done so, the overwhelming focus has been examining effects of liberalization, restructuring, and regulatory reform). The mindset of Indian academia tends to be compartmentalized, with little space for cross-disciplinary research. Science and engineering departments are more focused on

---

[279] In the United States, deregulation and a broader corporate trend towards reduction in R&D spending in the 1990s led to utilities cutting back on the magnitude and nature of their R&D efforts (GAO, 1996), although the Electric Power Research Institute, whose membership represents most utilities in the country, has maintained a significant (but declining) R&D budget.

[280] One singular exception is the recently released Integrated Energy Policy report by the Planning Commission, for which the Commission had placed a draft report on its website and requested comments. Given that significant parts of the final report were different from the draft, one can conclude that public comments may have had some influence. However, the Planning Commission has not released any statements about what comments it received, nor has it stated how these comments were incorporated in its final report.

[281] Guy de Jonquieres, "Asia needs a more active market in ideas", Financial Times, 30August 2006.

[282] For example, A.K. Bhattacharya argues that expert committees (at least for economic reforms) are desirable and serve a very useful purpose in a democratic system, as the committee reports and recommendations create a platform for debate on proposed policy changes among stakeholders and civil society in general. See: A.K. Bhattarcharya, "Dissent over expert committees" Business Standard, 13 September 2006.

research and development of technologies, rather than on assessing policies governing their entry and diffusion into the market. Similarly, social science departments tend to highlight the political and economic aspects, without a deeper analysis of technologies and technical issues. In many cases, the rigid institutional walls that characterize Indian academic institutions do not make space for the interdisciplinary nature of policy research, whose analysis is based on a disparate set of disciplines – economics, science, engineering, political science and social sciences. Most NGOs are generally busy with fire-fighting issues of the day and many may not have the technical capacity to do the required analysis. Major think-tanks generally focus on specific projects that are often funded by international agencies or groups from industrialized countries.

In fact, it may be argued that external organizations play a significant role in shaping the power-sector policy in the country (partly made possible by the vacuum created by the absence of domestically-driven policy research and analysis efforts).[283] For example, aid agencies such as USAID and Department for International Development-UK (DFID) helped initiate the restructuring of the Indian power sector, through funding that catalyzed major World Bank projects in this area and leveraged its funds for a large impact (Dubash and Rajan, 2001). Furthermore, the lack of local expertise also allows for the injection, acceptance, and diffusion of policy approaches, often developed by international consultants, without full consideration of how these approaches might play out in the Indian context. For example, in the case of Orissa's reforms, international consultants that were selected and paid for by the World Bank and DFID (then ODA) played a major role in designing and drafting of a state law to create an independent electricity regulator. The Orissa approach (also known as the World Bank model in India) then served as the basis for reform efforts in other states as well as for the central government's Electricity Regulatory Commission Act (Dubash and Rajan, 2001; Dubash, 2005). This has now heightened sensitivities among many policy makers against hastily ideas and policies, particularly those pushed by international agencies. This is particularly true in the GHG mitigation area (as discussed earlier in section 3.4). There is also a potential for backlash now, at least in some quarters, against such activities.

The lack of policy research capacity also hinders integration of power-sector policy with cross-sectoral issues such as national security, environment and labor. This is particularly important as the power sector itself is in a period of transition and there are major emerging issues such as energy security and climate change. Such cross-sectoral integration is critical to defining power-sector policy in the context of broader policy objectives, which in turn is needed to avoid the piecemeal approach that often occurs. Although the recent effort by the Planning Commission to draft an integrated energy policy is one such process, much more analytical focus is needed on this issue.

Another corollary of this lack of focus on policy research is the absence of systematic data collection. India has reasonable good systems of data collection in many sectors – one of the few positive legacies of the British colonial times – and to some extent, this is true of the power sector also. The CEA, for example, collects and makes publicly available a fair amount of data on the power sector. Yet, detailed data are often not available to the public and, in fact, not even

[283] This is true not only in the power sector but also other related issues such as climate change (see Kandlikar and Sagar 1999)

to the relevant statutory bodies. Furthermore, the reliability of the data is often under question, since primary data and information about data collection methodology are often not public available.

This is unfortunate since the availability of reliable data is the foundation of any analytical effort, and in the absence of data-driven analyses, it becomes difficult to understand the real performance of the sector and the factors that ail it. Public dissemination of data and its subsequent analysis can also serve to support regulatory efforts (as has been shown by policy experiments in other countries) through public pressure on facilities and firms as well as through influence in financial institutions.

5 Technology policy for the energy sector

The energy sector, and energy technologies in particular,[284] plays a prominent role in national policies and planning for a number of reasons. First, the energy area has a 'public goods' characteristic: the provision of energy services such as, heating (both for cooking and space heating), cooling and lighting is necessary to directly satisfy basic human needs; energy also underpins most other activities such as agricultural and industrial production, transport, and communications which buttress economic and human development. Second, the reduction of the environmental and social externalities (such as local and global air pollution) related to the energy extraction, conversion and use has public benefit. Energy technologies are crucial in reducing these externalities.

Third, the government and the public sector play a dominant role in the Indian energy sector, as in many developing countries (see sections 2.3 and 4.4.3). Hence, government policies and actions primarily determine the direction and focus of the energy sector, with the private sector and 'markets' having a limited role. Even in industrialized countries, where the private sector dominates the energy area, the government plays a key role in shaping the energy sector by setting societal goals and uses incentives and regulation to generally guide the sector. Theoretically, the market then determines the allocation of resources, technology choices, and pathways to meet the required goals.

Fourth, the development of energy technologies and their introduction into the marketplace require long time scales and sufficient investment in their development; private players may be unwilling under such conditions to invest the resources necessary to develop suitable energy technologies even if these benefit society more widely. Hence, the scale and complexity of these technologies often necessitates a role for the government in their development. For example, the large investments needed for building power plants, the private sector may not necessarily invest in cleaner or more efficient technologies—since these are generally more expensive—without government support (for example, through R&D) and regulation. Furthermore, high-investment energy technologies, such as coal power plants, also have a long lifetime (~50 year) in the energy sector; hence, current technology investments have significant security, environmental, and societal ramifications for the long term. Finally, faster deployment and scale-up of energy technologies also may require government policies and support.

Thus, there is a strong rationale for government policies that support the research, development, demonstration, and deployment (RD^3) of appropriate technologies (by helping overcome technical, financial, informational or other institutional barriers, and helping maximize technological learning from deployment efforts). A well thought out and robust technology policy based on empirical data and analysis can greatly facilitate and further the energy technology development and deployment processes in India.

[284] Energy technologies play a central role in enabling the provision of energy services: a) they enhance the exploration for and extraction of primary energy supplies such as coal and hydrocarbons; b) they allow the conversion of these primary energy sources to more usable forms such as electricity and refined petroleum products; and c) they allow for the ultimate utilization of these energy forms in a range of end uses.

It is also important to note that such a technology policy must be embedded in a rational energy policy for the country that views energy as the means towards social and developmental goals for the country, and not an end in itself. In fact, by getting the energy policy 'right', one can get the policies in other spheres to also fall into place (Lovins, 1977).

5.1 Technology policy and decision-making in the coal power sector

While subcritical PC technology was the standard technology worldwide for utility-scale coal-based power generation and the technology that has almost completely dominated coal-based generation in India, there is now, however, a range of advanced, more efficient, and cleaner technologies for producing electricity using coal. PC technology has become more efficient with the use of supercritical steam parameters (which requires advanced materials) and has widespread use in industrialized countries. Supercritical PC and fluidized-bed combustion (FBC) technology is being adapted for burning lower-quality coals and for high-sulfur and high-moisture-content coals. In addition to combustion, coal gasification combined with combined cycle operation is nearing commercially availability and will allow for further reductions in emissions, including carbon dioxide. These various technologies are at different stages in their development and deployment worldwide. They also have different performance characteristics and different technical needs and barriers to overcome, but it is quite likely that some or all of these emerging technologies will begin to be commercially deployed worldwide over the course of the next decade or so.

Thus, unlike in the past, when there was only one main technology worldwide (subcritical PC), there is now a menu of technology choices for India to consider for the coming years. Given these existing and emerging options, the Indian coal-power sector could itself go in a number of possible directions, yet it is far from clear what the appropriate technology choices might be in the Indian context. All of the current and emerging technologies have their strengths and limitations – hence, some technologies are better suited for meeting the specific challenges and constraints of a particular country.

At the same time, the nature of challenges and constraints faced by the Indian coal power sector (discussed in sections 3 and 4) are evolving. For example, the energy security challenge will likely become more pressing as the global energy demands push against constrained supplies in the oil and gas sectors, which in turn can have spillover effects on the coal sector, both worldwide and specifically for India. Climate change is another issue that increasingly being recognized by analysts as possibly the most daunting challenge that the current global energy system may face in the 21st century. As the uncertainties associated with issues such as climate sensitivity and the relation between temperature rise and climate impacts become better resolved, global and national GHG mitigation targets and timetables needed to meet UNFCCC goals will also become clearer. Response to climate change will influence and indeed help determine coal power technology trajectories worldwide; reducing emissions from the Indian coal power sector is certain to become an important future challenge. Specific to India, uncertainties about the extent of domestic coal resources, their availability, and about future institutional framework and reform processes, will also influence technology choices.

The dynamic nature of power generation technologies, the challenges and constraints faced by the coal sector (both in India and worldwide), and the interactions between all of these suggest a plurality of possible energy technology futures for coal power in the country. Yet, the reality of current decision making in India suggests otherwise. Technology policy in the power sector is primarily driven by the need to increase generating capacity, which has the result of deploying the least risky and cheapest technology (subcritical PC). On the other hand, growing international and domestic concern about limiting carbon emissions from the power sector has implicitly pushed the debate on technologies towards rapid IGCC deployment in India, without systematic analysis of other alternative technologies or of different pathways to deploy clean coal technologies in the country. Furthermore, technology decisions tend to be made primarily by small groups of experts and technocrats, without much (if any) broader participation and stakeholder discussion and input, especially from environmental groups and local communities.

The existence of many different possible technology futures does not however mean that India can afford to invest in all options. Decision-makers[285] in the Indian coal-based power sector must assess, and choose amongst, the available technologies (worldwide and developed indigenously), keeping in mind India's historical trajectory and its current and future needs, challenges and constraints. Even if there is a consensus decision on what might be the best (set of) technologies for the country to pursue, there is still the question of what is the best approach to move down that path. For example, for any given choice, there remains the question of whether to import, adapt, or indigenously develop the technology.

Therefore, a focus on technology policy in the coal power sector is imperative in order to assist decision-making and to ensure that the choice and trajectory of energy technologies is appropriate to the current and emerging needs and context of the country and that development and deployment is suitably supported and furthered in a suitable timeframe and manner.

[285] The key technology decision-makers in the Indian power sector are government officials and officials of public-sector corporations. This is unlike the situation in U.S. and other industrialized countries.

5.2 Technology Roadmapping

There are now a range of technological options – current and emerging – that can help meet the challenges (highlighted above) facing the Indian coal-power sector. In an evolving technology landscape, it would be risky, if not foolhardy, to pick technology winners *a priori* – the design of the technology policy must take all these options into account. Hence, a systematic and objective analysis is required to help choose among these various technical options and assess the best approach for deployment. Such a critical analysis is crucial for India, as a developing country with limited financial and other resources at its disposal, to be judicious and efficient in its policy approach to the technological aspects of its energy sector. Also, given the range of challenges and constraints facing the Indian energy system and democratic nature of the country, any discussion about the options must involve all the key stakeholders (not just for reasons of fairness but also in terms of ultimate effectiveness of the process and outcome). More importantly, the government must play a unique and key role in bringing together these stakeholders, as an effective neutral party. However, the government must also be particularly sensitive to the fact that it has a very strong presence in the power sector, and therefore, even as the government must put together this process, government institutions must not dominate the proceedings.

In effect, a suitable technology policy requires the development of a strategic technology plan. It is precisely in this case that technology roadmapping can add substantial value to technology policy in the coal power sector. Such a roadmap would highlight the suitable path(s) forward from among various options based on a comparative assessment of the state and performance characteristics of various technologies and the resources required for their implementation. This will help ensure that the right capabilities and resources are in the right place at the right time to achieve the desired objective (Lee and Park 2005). Technology roadmapping is one of many technology planning tools that countries/industries/firms undertake when identifying, selecting, and investing in technologies that are needed to meet their product/service requirements. Technology roadmapping is most useful when the technology investment decision is not straight forward, i.e., when it is not clear which alternative to pursue, how quickly the technology is needed, or when and how to link up multiple resources and institutions to coordinate the development of multiple technologies (Garcia and Bray, 1997).

Technology roadmapping is a needs-driven iterative planning process that brings together teams of experts and stakeholders to develop a framework for organizing and presenting critical information about needs, performance targets and time-frames, technology characteristics, and trade-offs among different alternatives to help decision-makers make appropriate technology decisions and to effectively leverage their investments (Garcia and Bray, 1997). The end result of the process is a document (the "roadmap"[286]) which identifies the path to meet the envisioned goals. It should be noted, though, that the roadmapping process and the technology roadmap are tools that provide a new way of thinking about needs and technologies. They cannot, by themselves, make decisions; people make decisions – not models (Paap, 2006). However, by

[286] There are different types of technology roadmaps: product technology roadmaps, emerging technology roadmap, issue-oriented roadmap, etc. (Garcia and Bray, 1997). In this paper, we have broadened the "product technology roadmap" of Garcia and Bray to entire coal-power sector, including a wider set of stakeholders.

going through the roadmapping process, decision-makers will be better equipped to make decisions.

The roadmapping process will also help form dynamic partnerships between public and private sector organizations, which are critical in an evolving marketplace. By stimulating dialogue and collecting valuable information, the process encourages such partnerships and helps establish better policies and planning priorities for both industries and government (Industry Canada, 2000).

5.2.1 Elements of a technology roadmapping process

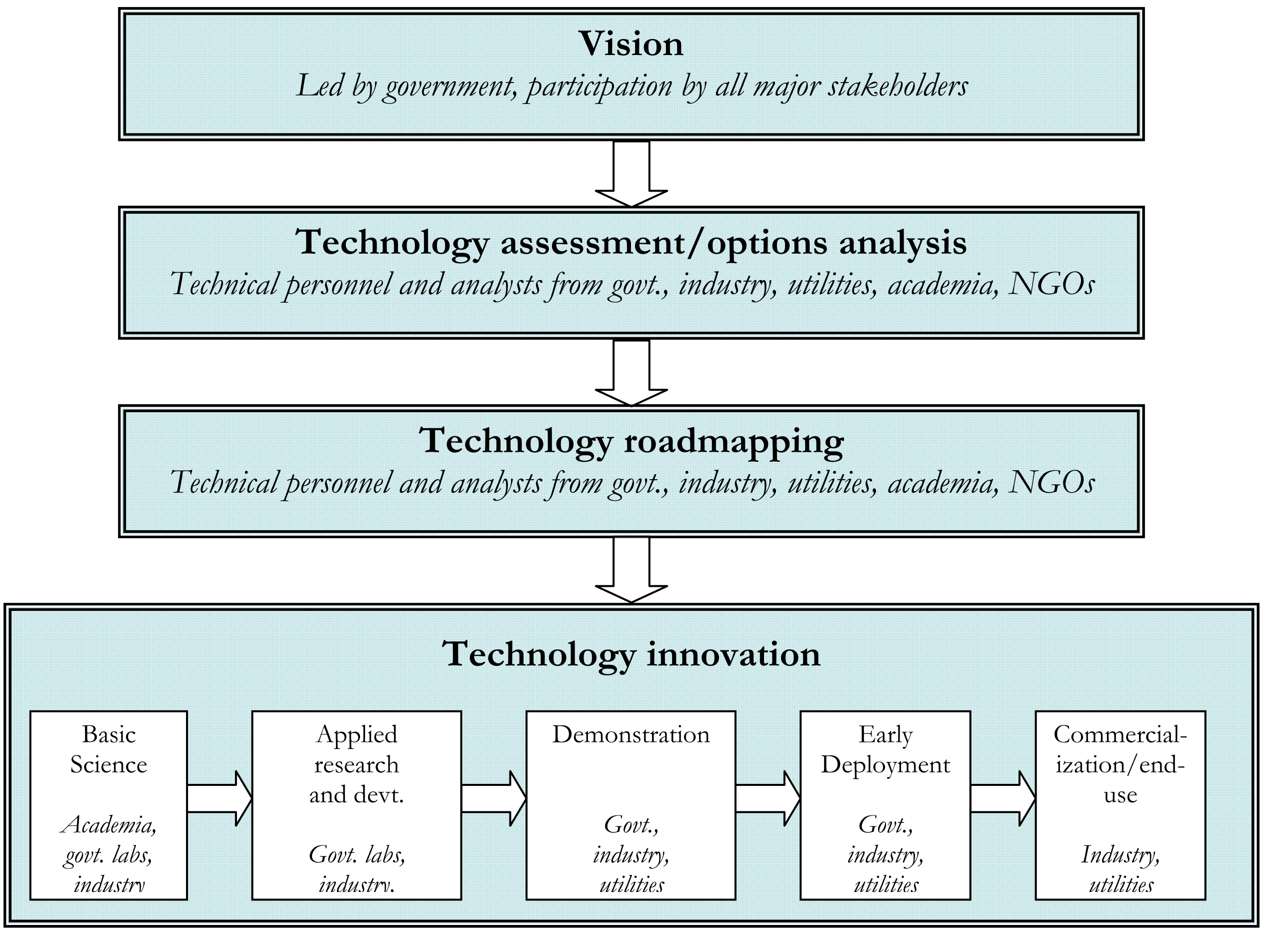

Figure 38: Outline of a technology roadmapping process.

The first step in developing a strategic roadmap is to build consensus on a vision for the future that takes into account the various challenges and constraints, and the perspectives of various stakeholders on how to prioritize and reconcile these challenges with given constraints (see Figure 38).[287] For the coal-power sector, stakeholders include end-consumers (industries, agriculturists, domestic consumers, etc.), technology manufacturers, coal producers and

[287] As Sobhan (2000) notes, “Inappropriate policies tend to reflect a deficiency of vision and low commitment originating in a lack of ownership over the policy as well as inadequate consultation with the relevant stakeholders in the policy-making process.”

transporters, utilities (public and private), project financiers, relevant government agencies, academics, NGOs, and other citizen groups. Given the varied views of these stakeholders, the government would have to play an important role in bringing these stakeholders together to build consensus on the overall vision for the coal power sector. It is important that government be inclusive and that the stakeholders are involved early in the process, so that the consensus-driven vision can be a common platform for the country.

After deciding on the vision, the focus can shift to examining the various existing, emerging, and potential technological options that are available to realize the vision. These options have to be assessed and compared on a number of dimensions, such as cost (current and/or projected), technical and environmental performance, technological complexity, technology development uncertainty and risk, fuel flexibility and capability for indigenous development/adaptation. Given that such an exercise is intended to assist with decision making for the future, technological forecasting plays an important role.[288] Selection of the appropriate technology and pathway depends not just on the endogenous features of the technology but also characteristics of the geographical, economic, and institutional context in which the technology will be implemented. The assessments must be specific to local situations, keeping in mind the country's historical trajectory and its current and future needs, challenges and constraints. Thus, factors such as technological and institutional capabilities within the sector, financial resources available, and the risk-profile of the implementers will have a significant bearing on the choice of a strategic roadmap.

Once the outlines of the technology roadmap have been developed, i.e., a suitable technology trajectory has been agreed upon, the focus can then shift to ways in which the chosen technology trajectory can actualized. This requires a systematic analysis of the technological underpinnings of every step in the strategic roadmap, i.e., addressing the questions of what are the kinds of technologies and what is the sequencing that is necessary to move along the roadmap. Particular attention must be given to the present status of technologies, specific research or development activities required, and the ways in which necessary component technologies might be best combined to create the necessary technology or 'product' that is called for in the strategic vision.[289] This, in turn, will help build a better understanding of the required capabilities and activities – thereby informing the technology policy.

While the technology roadmap intends to elucidate the technology trajectory that is relevant to a particular context, successful implementation of the selected technologies also requires attention to demonstration, early deployment, and commercialization efforts, i.e., the entire innovation chain. The relevance of all elements of the innovation process, not just R&D, to the steps in the roadmap needs to be clarified. In some cases, particular research efforts may be needed to help develop or refine aspects of a specific technological component. In other cases, a targeted demonstration effort, aimed at testing aspects of the technology in the field, may be desirable.

[288] In fact, it has been suggested by Porter et al. that a better term might be "technology futures analysis".

[289] We would like to highlight here the fact that any 'technology' or 'product' often consists of a number of component technologies that all work together as a system (Sagar and Mathur). For example, an automobile consists of technological sub-systems such as the engine, the drive-train, the chassis, and the body; different combinations of different sub-systems lead to different vehicles. Similarly, a natural gas combined cycle power plant consists of gas turbine, a waste-heat boiler, a steam turbine and generator(s), all of which are technological sub-systems.

And in yet other cases, policies to assist the early deployment of a new technology may be particularly important to help overcome market or informational barriers. While different pieces of the innovation process require different kinds of actors and different kinds of coordination amongst these actors, it should be emphasized that the process itself should not be thought of as being linear – in reality, innovation is a complex process, involving feedbacks and linkages between the various stages and among the various actors (see Figure 39). While we have presented a simplified innovation model in Figure 38, there are more complex models of innovation (Kline and Rosenberg, 1986).

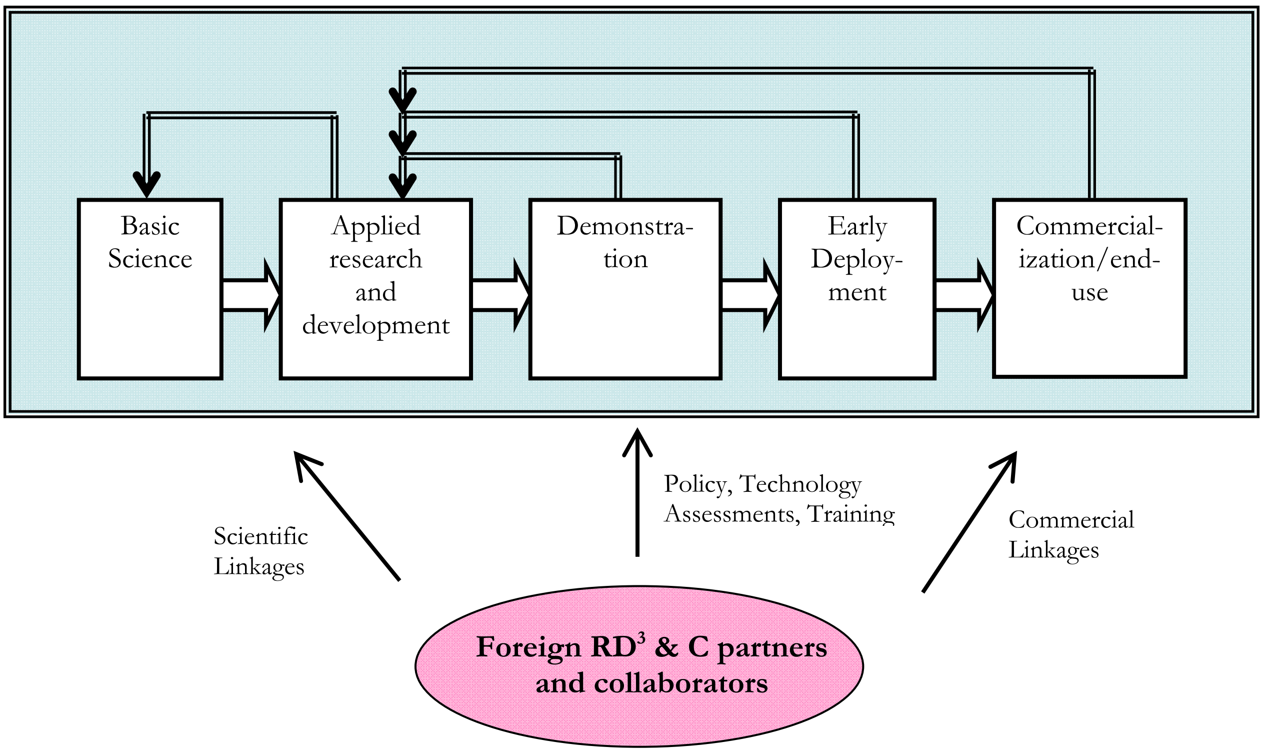

Figure 39: Innovation Linkages and Feedback, including foreign partners and collaborators.

As part of the technology roadmapping process for a developing country such as India, it would also be useful to examine the need for, and specify the roles of, foreign partners and collaborators at each stage of the innovation process, so that they can help overcome lacunae in domestic capabilities. For example, linkages with appropriate international research organizations (such as the national laboratories in industrialized countries) and engineering firms might add significant value and speed up basic and applied research for specific technologies. It might also be necessary to utilize the expertise of foreign analysts and consultants for policy analysis and technology assessments, although care must be taken to involve domestic experts to ensure a suitable incorporation of local perspectives and build up indigenous analysis capacity. Finally, as we move closer to the technology deployment and commercialization phase, commercial tie-ups and joint venture projects become more feasible. In such cases, it is very important to assess whether the foreign collaborations are need-based and how foreign linkages and tie-ups can best further the technology strategy and the roadmap.

A roadmapping process must be knowledge-based, transparent, and inclusive with active participation of all stakeholders – the central and state utilities, the central and state regulatory agencies, national and international financiers, coal suppliers, power plant employee unions, engineering associations, etc. The roadmap and the roadmapping process could significantly strengthen decision-making in the country; thus explicit linkages to key policy makers in the country are necessary so that the effort can ultimately help underpin a national clean coal technology policy that will shape and drive the RD^3 activities and programs necessary for a chosen technology roadmap.

It is also worth noting that roadmaps should not be thought of static – given that they intend to take an "extended look at the future" (Galvin 1998), uncertainty is an ineluctable part of the exercise. Hence roadmaps should be best thought of as dynamic and part of an iterative procedure that regularly assesses the landscape of technological possibilities and the application context. Thus, the roadmapping process may be as important, if not more, than the roadmap itself. Furthermore, in uncertain environments, it may also be useful to engage in multi-scenario roadmapping (Strauss and Radnor 2004), an approach that combine scenario-planning and roadmapping.

Finally, it should be noted that the value of a roadmap is only as good as how it gets implemented. Thus, the implementation planning, in terms of policies and institutional changes, should also be considered as part of the roadmapping process. The government would need to devise and implement relevant policies commensurate with the vision and goals, as determined through the roadmapping process. It would also need to provide adequate and sustained funding and incentives for innovation activities. Since the technology roadmap cannot be implemented without buy-in from industry, utilities, and other key actors, their participation from the initial stages of the roadmapping process to the implementation planning is most crucial.

5.2.2 Experiences from other countries

Technology roadmapping in the coal power sector is not new, as almost all major countries, excluding India, that rely on coal for generating electricity have already assessed a possible range of cleaner coal technologies and formulated cleaner coal technology roadmaps. Industrialized nations, such as United States, United Kingdom, Australia, Japan, Canada, and Germany, already have specific clean coal technology (CCT) roadmaps to meet their particular goals and have been devoting enormous resources to make progress on their roadmaps.[290] International efforts such as the IEA Clean Coal Centre, European Union's PowerClean program, and the Carbon Sequestration Leadership Forum are also engaged in technology roadmapping (IEA, 2005b).

The process of developing these roadmaps involved many stakeholders who reflected considerably on the envisioned roadmap. For example, the Electric Power Research Institute (EPRI) began an "Electricity Technology Roadmap" initiative in 1997, involving more than 200 organizations, including energy companies (domestic and international), equipment manufacturers, government agencies and research laboratories, universities, foundations, engineering and consulting firms, trade associations, financiers, environmental groups, and

[290] For a brief comparison of these many roadmaps, see: http://www.raeng.org.uk/events/pdf/Geoff_Morrison.pdf.

others (EPRI, 2003). In 1999, this stakeholder group led by EPRI determined five broad "destinations" representing critical goals for the sector. In 2003, these goals were updated and more detailed R&D plans were created to reach the desired destinations. According to EPRI, the Electricity Technology Roadmap is a "living document, owned by all industry stakeholders in the electricity enterprise" (EPRI, 2003). More recently, the U.S. Department of Energy came up with an integrated consensus CCT roadmap based on the EPRI roadmap and the roadmap activities of the Coal Utilization Research Council—an ad-hoc industry group promoting coal utilization R&D.[291]

Similarly, the Canadian CCT program was initiated by Canada's Climate Change Action Plan 2000. An Advisory Group with active participation and support by the Canadian government and the electric industry held several working sessions and public workshops. Various stakeholder and experts—similar to the EPRI initiative discussed above, albeit more focused on Canadian institutions—provided input in determining the eventual roadmap (CETC, 2005). Even the Chinese CCT program of 1995, which adopted a well-planned strategic program for research, development, and demonstration of CCTs, involved Chinese utilities, domestic and international equipment manufacturers, and engineers and academics from universities and national technical institutes. The Chinese program has focused on all aspects of coal utilization in the power sector from mining and coal beneficiation to advanced coal combustion/gasification and emission control technologies (Chikkatur, 2005).

Thus, the government and/or the industry leaders have generally take the lead in initiating a roadmapping process that involves a wide range of stakeholders and experts. In the Indian context, it would be useful to incorporate the lessons and salient features from the experiences of these various countries for its own CCT roadmapping process. Moreover, the roadmapping exercise can be extended many other industries, similar to the U.S. DOE's "Industries of the Future" program (EPRI, 2003).

[291] The vision of this consensus roadmap was based on Presidential Initiatives and 2001 National Energy Policy (NETL, 2004a). See: http://www.coal.org/PDFs/2002techarchive.html.

5.3 *Roadmapping Illustrated*

While it would be appropriate for the Indian government and industry groups to take the lead in organizing, participating and engaging various stakeholders in any roadmapping process for the coal-power sector, we believe that a demonstration of the roadmapping process will be of value to decision makers in India.

Therefore, in the following sections, we provide an illustrative vision for the coal power sector, identify possible (existing and emerging) technologies, assess their current status and future prospects in the Indian context, and then rate them against several key attributes. We then provide broad guidelines for the technology roadmapping process and the coal power technology policy in India.

5.3.1 Vision for Indian coal power sector

As shown in Figure 38, the first step in the roadmapping process is to determine a vision for the coal power sector. For illustrative purposes, we use what we believe to be a suitable vision for the Indian coal-based power generation sector, namely:

> *"Expand power generation at low cost while enhancing India's energy security and reducing impact on local and global environment."*

Thus, we suggest that coal power generation must be expanded to meet expected demand, albeit with four caveats: generation at low cost, enhance energy security, and reduce impacts on the local and on the global environments.[292] This vision supports the objectives laid out in the 2005 National Electricity Policy[293] to ensure adequate supply of quality power at reasonable cost to meet demand by 2012. While the Policy's key criterion for new technologies is cost-effectiveness, our vision builds on this by additionally highlighting the importance of enhancing energy security and improving environmental performance of coal power. This particular vision also incorporates the broad vision of the 2006 Integrated Energy Policy, which aims to "provide energy security to all" by reliably meet the energy demand of all sectors in a "technically efficient, economically viable, and environmentally sustainable manner" (Planning Commission, 2006). In addition, our vision explicitly recognizes that the climate issue will continue to gain momentum and India will eventually have to undertake some kinds of GHG-control commitments. Thus, we include the term 'global environment' in the vision and acknowledge the need to control CO_2 emissions from power plants as a key measure to reduce India's GHG emissions at some point in the future.

While we believe that our above vision is appropriate for the coal power sector (and for the power sector in general), we also note that there could be other visions for the power sector (or those that give different levels of emphasis to different elements).[294] Different stakeholders

---

[292] Note that the term "reducing impact" is used rather than a more restricting term such as "minimizing impacts on local and global environment" or a weaker term such as "protecting local and global environment." The key, of course, is to determine how much reduction and when to implement them.

[293] http://powermin.nic.in/indian_electricity_scenario/national_electricity_policy.htm.

[294] Other possible visions for the coal-power sector could include, for example:

likely will have very different preferences and perspectives, and their views must be incorporated into a common vision.

Thus, it is important that the ultimate vision for India's coal-power sector emerge out of an inclusive process led by the Government, as discussed in section 5.2.1. Nonetheless, to continue with our illustration of the process, the above vision will be used as a guiding principle for technology assessment and analysis.

- Generate electricity most efficiently with minimum consumption of resources and maximum utilization of generated electricity, or
- Generate electricity with zero emissions – particularly minimizing CO2 emission, or
- Generate the cheapest possible electricity using coal, or
- Minimize the use of foreign technology and rely heavily on indigenous technologies for electricity generation, or some combination of these goals.

Each of these overarching goals will result in different roadmaps.

6 Assessment of technological options

An important first step for a technology assessment is to identify the technologies that are to be reviewed and analyzed. Given the large and changing technology landscape, prudence suggests that we focus on the subset of technologies that are most relevant to meeting needs, challenges and constraints of the sector. Table 27 and Table 28 summarize the implications of aforementioned challenges and constraints for technology choice. These implications for technology choice lead to the specific set of technologies that are assessed in this section.

Challenges		
	Description	*Implications for technology decision-making*
Need for rapid growth	• Meeting socio-economic goals requires a rapid increase in the availability of electricity services.[295] • A large fraction of the new growth in electricity is expected to be based on coal.	Technologies must be commercially mature to be rapidly deployed in the short-to-medium term.
Enhancing energy security	• Coal is by far the most significant domestic resource, and increased use of coal is linked to energy security. • Power generation that relies on multiple fuels, sourced from diverse locations, also can increase energy security.	Technologies must be able to use domestic coal and/or allow fuel flexibility, so that other fuels, such as petcoke and biomass, can be utilized.
Protection of local environment	• Coal-power plants strongly impact the local environment by causing pollution of air, water and land resources. Reducing these impacts over time is an important priority for the government.	Technologies with high-efficiency, combined with better pollution-reduction technologies, are needed.
Carbon emissions mitigation	• Coal combustion accounts for about 40% of total CO_2 emissions of the country. Given that more than 70% of the coal consumed in country is used for power generation, reduction of CO_2 emissions will significantly impact coal power plants. • The nature and timing of emission targets are unclear and will likely not be determined in the short-term.	Although there is no requirement for capturing CO_2 from power plants, high-efficiency technologies that might allow for low-cost carbon capture are most relevant.

Table 27: Challenges and their implications for technology decision-making.

[295] In addition to capacity addition, increased availability of electricity services can be obtained though better demand management, reduction of theft, and improvements in efficiency of transmission, distribution and end-use of electricity.

Constraints		
	Description	*Implications for technology decision-making*
Coal availability and quality	• There is currently significant uncertainty about the quantity of coal reserves in the country. While there may be 250 BT of coal resources, exploitable coal reserves may only be 45-70 BT. • Coal demand is expected to outstrip domestic supply – leading to increased imports. • The quality of domestic coal is poor with high ash content and low calorific value.	• Technology choices will likely be constrained by the quality of domestic coal. • Extent of available coal reserves and the increased use of imported coal will impact technology choices in the long-term.
Finance resource limitations	• Financial resources are limited, particularly in the State sector, because past policies have damaged the financial viability of the sector. Although equity shortfalls are of primary concern in the short-term, enormous outlay of capital is required for accelerated growth in the power sector. • Low cost of generation and supply is important for increasing electricity access for the poor.	• Cost is a key criterion for technology selection; therefore, technologies with high efficiency and low capital costs are favored. • Technology costs are also linked with maturity and indigenous technological capacity.
Limited technical capacity (R&D, manufacturing, and O&M)	• There has not been enough investment in developing coal power technologies in India, and most of the existing effort has been limited to BHEL. • There is significant capacity for manufacturing and O&M within BHEL; NTPC and other utilities also have significant O&M capacity. • Capacity for innovation in the country is limited, with little R&D coordination between academia, government and industry.	• Technology choices need to be consonant with indigenous capacity. Upgradation of technological capacity in the country must be considered. • Limited investment in technological capacity might affect future indigenous technology development.
Institutional issues	• Historical power shortages have created a panic-mode of operations, wherein there is more emphasis on mitigating short-term problems, rather developing long-term strategies. This has led to a narrow focus on generation, with risk-averse attitudes towards new technologies. • Lack of significant domestic policy research capacity has hampered systematic technology planning.	• There has been an emphasis on technology replication rather than innovation. • Limited competition, dominance of government-owned enterprises, and lack of long-term technology planning limit the development and deployment of new technologies. • Successful choice and deployment of technologies will require paying greater attention to institutional issues.

Table 28: Constraints and their implications for technology decision-making.

While combustion continues to remain the dominant pathway for power generation using coal, a number of advanced (relative to subcritical PC) coal technologies have been developed to meet the worldwide challenge of making power generation cleaner, more efficient, and more able to utilize coals of varying quality – characteristics that are also relevant in the Indian context.

Pulverized coal technologies have improved, resulting in increased efficiency and reduced local pollution. New combustion approaches using circulating fluidized-beds are being introduced to utilize lower quality coals including waste coal and washery middlings. Combustion with pure oxygen ("oxyfuel combustion") rather than air is also being considered for ease of carbon capture and storage. Efforts are also underway to demonstrate and commercialize electricity generation using coal-gasification-based systems. Entrained-bed gasifiers have also been used commercially for converting coal into a high-energy-content gas that can be used to make methanol and hydrogen for making chemicals and Fischer-Tropsch (F-T) liquids such as synthetic diesel (thereby allowing the possibility of linking the power and the hydrocarbon sector in an entirely different way).

Given this variegated and evolving landscape of advanced technologies, we believe that the following options are relevant in the Indian context:

- Supercritical pulverized coal (SCPC)
- Ultra-supercritical pulverized coal (USCPC)
- Circulating Fluidized-bed Combustion (CFBC)
- Pressurized Fluidized-bed Combustion (PFBC)
- Oxyfuel PC/CFBC
- Integrated Gasification Combined Cycle (IGCC)
    - Entrained-flow gasifiers
    - Fluidized-bed gasifiers
    - Moving-bed gasifiers

To reiterate, the technologies chosen above reflect our view of the most relevant technologies in the Indian context; this list, by no means, is inclusive of all possible technologies. Over time, other technologies (such as pressurized pulverized coal, chemical looping, fuel cells, etc.) might gain in their applicability, and they would need to be considered at that time.

In the following sub-sections, we summarize the current status -- both worldwide and in India – of these technologies, and discuss their possible future development trajectory. Detailed technical information about these technologies is available elsewhere,[296] and it is not reviewed here. Note also that only coal-based utility-scale power generation technologies are reviewed here; a discussion of other fossil fuel based technologies (natural gas combined cycle (NGCC), combined heat and power, heavy-oil-based plants, etc.) and of better/cleaner coal mining technologies are outside the scope of this work.

In addition, we analyze aspects of carbon capture and storage (CCS) in some detail, as CCS is becoming a topic of greater relevance and current interest in India.

[296] See, for example: Merrick (1984), Ghosh (2005), IPCC (2005), and references therein; websites such as http://www.iea-coal.org.uk/site/ieaccc/home and http://europa.eu.int/comm/energy_transport/atlas/htmlu/heat_and_power.html.

6.1 Advanced pulverized coal – supercritical steam generation

The basics of the pulverized coal (PC) technology have already been discussed earlier in section 2.2.1. Since the late 1950s, the PC technology worldwide has continued to evolve towards greater (net) efficiency from about 33% to about 38-42% (HHV) in the 1990s. Much of these improvements have come from making various modifications to the standard PC technology, including (DTI, 1999):

- increases in main and reheat steam temperatures and main steam pressure by transitioning to supercritical conditions;[297]
- changes to the cycle configuration, such as increasing the number of reheat stages and the number of feed-heaters, with associated increase in final feed water temperature;
- changes in the boundary conditions of the thermal cycle, principally by reducing the boiler-flue-gas exit temperature and the condenser pressure through more effective cooling;[298]
- reductions in auxiliary power consumption;
- improvement in the performance of the individual plant components (coal combustion, turbine efficiency, pump efficiency, condenser performance, etc.).

Advanced PC technology can generally be categorized according to steam characteristics into supercritical, advanced supercritical and ultra-supercritical technologies, as shown in Table 29. The key technological breakthrough for using advanced PC technology is the development of various alloys of steel that can withstand high temperatures, pressures, and corrosion.

Category	Unit	Subcritical	Supercritical	Advanced Supercritical	Ultra Supercritical (USC)
Year of introduction		<1990	1990	1995-2000	2000-
Live steam pressure	[atm]	<170	220-260	270-300	>300
Live steam temperature	[^{o}C]	540	540-560	560-600	>600
Reheat steam temperature	[^{o}C]	540	560	580	>600
Reheat		None	Single	Single	Double
Generating efficiency (LHV)	[%]	~38	~41	~44	46+

Table 29: Classification of pulverized coal technology. These categories are approximate, and may not be generally accepted worldwide. Source: Adapted from (Lako, 2004).

Some of the earliest supercritical power plants were installed in the late 1950s/early 1960s in the United States.[299] There are now more than 500 supercritical units operating worldwide, with

[297] Generating supercritical steam requires the 'once-through' technology, where water is directly evaporated into steam without any storage drum.

[298] Condenser pressure can be dramatically improved by using colder cooling water. For example, a coastal station in Denmark with 10^{o}C seawater cooling can achieve 5% (2 percentage points) better efficiency than an identical tower-cooled power plant in India (DTI, 1999).

[299] The 1960 Eddystone Unit 1 near Philadelphia was the first power plant to use ultra-supercritical steam pressures greater than 340 atm (5000 psig) and double reheat temperatures of 650/565/565^{o}C. Currently, the Eddystone unit is

46% in the former U.S.S.R. (Ghosh, 2005). Within the OECD, supercritical technology, because of its high efficiency, has been primarily installed more in countries with high coal price (Germany, Netherlands, Denmark, Japan, Korea) and less so in countries with low coal prices (United States, Canada, Australia) (Ghosh, 2005). The current state-of-the-art PC plants are mainly in Europe and Japan.

Lack of operator experience and technical problems, such as boiler tube leaks and corrosion at high temperatures, during the 1960s and 70s in the United States led to a perception that supercritical units are less reliable than subcritical units (IEA, 1998; Ghosh, 2005). This perception, combined with low coal prices, did not favor the installation of high-efficiency coal technologies in the United States.[300] However, these technical problems have been resolved and there is extensive operational experience in Europe, Russia, and the United States. Hence, supercritical PC technology is now acknowledged as a mature, reliable technology. Today's operating supercritical units have typical average availability of 85%[301] – matching the average availability and reliability of sub-critical PC units. Supercritical units also have better efficiencies at partial load, in comparison to sub-critical units, although they have lower load-following ability under advanced steam conditions (DTI, 1999).

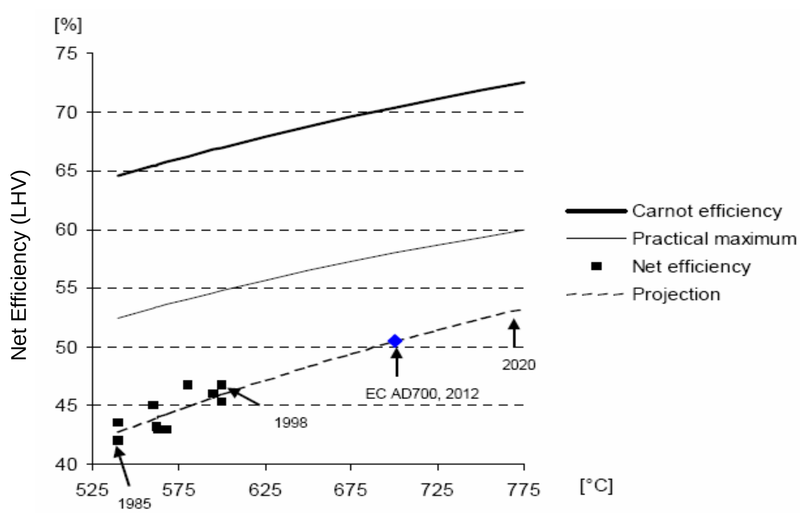

Figure 40: Steam temperature and net efficiencies of leading supercritical units. Net efficiency of European power plants (1985-1998) is shown along with projections for the future (see text). It has to be noted that European plants tend to have higher efficiency because of colder air and water temperatures; see section 7.1. Source: (Lako 2004).

The current state-of-the-art advanced PC technology is being used in the coal-based 400 MW Avedöre unit 2 in Denmark with steam parameters of 305 bar/582 °C/600 °C (with a net efficiency of 46% (HHV) (Bendixen, 2003; PowerClean, 2004)) and Tachibana-Wan 1 & 2 (Japan), 2x1050 MWe, 250 bar, 600/610 °C, both commissioned in 2001 (PowerClean, 2004).[302]

---

operating at 320 atm (4700 psig) and 600 °C, and remains as the power plant with the highest steam conditions in the United States (Palkes et al., 2004).

[300] As of 2004, less than 15% of coal-based units in the United States used supercritical PC technology (PowerClean, 2004).

[301] The average availability for Denmark's five supercritical units from 1993-95 was ~89% (DTI, 1999).

[302] The efficiencies for European power plants are higher because of lower ambient temperature of cooling water. See section 7.1.

The state-of-the-art for a lignite fueled power plant is the German Niederaussem with steam parameters of 260 bar/580 °C/600 °C and net efficiency of 42-43% (PowerClean, 2004). The trajectory of the efficiency of the more recent European power plants is shown in Figure 40.

Major worldwide manufacturers of supercritical boilers include Alstom, Babcock & Wilcox, Babcock-Hitachi, Burmeister & Wain Energy (BWE), Foster-Wheeler, Kransny Kotelshchik (Taganrog Boiler Works), and Mitsubishi Heavy Industries (MHI). Alstom, Leningradsky Metallichesky Zavod (LMZ), MHI, Siemens, and Toshiba are some of the leading manufacturers for supercritical turbine-generators. These manufacturers can provide a wide range of sub-critical to ultra-supercritical units of varying sizes, and have the capability to sell PC boilers and TG sets to customers worldwide. In the case of China, though, several domestic companies such as Dongfang Electric Corporation, Shanghai Electric Company, and the Harbin Power Equipment Company have dominated the manufacturing of power-generation equipment, and they have had technology linkages with the major multi-nationals. These Chinese companies are now also selling their equipment in international markets, although they might not be able to provide the same range of equipment as their industrialized-country counterparts.

Although PC boilers can burn a wide range of feedstock, such as hard 'black' coals, lignite (brown coal), heavy oil,[303] coal-biomass mixtures, and residual wastes (MSW, sewage sludge, etc.), thermal efficiency decreases when the calorific value of the input falls outside the boiler's designed range. However, if designed properly, the reduction in thermal efficiency can be relatively small even as the coal quality is decreased significantly. For example, a recent U.S. EPA study shows that the thermal efficiency for subcritical and supercritical PC plants is reduced by 8-9% even when the input coal's heating value is almost halved (Khan et al., 2005).[304] There are also demonstrations of co-firing with biomass and residual wastes in Europe, where PC boilers have been operated with up to 15% biomass/waste mixed with coal (PowerClean, 2004). Such biomass co-firing is generally aimed at reducing CO_2 emissions (using biomass) and for eliminating high-carbon content wastes.

Advances in flue gas cleaning have helped to reduce power plant emissions significantly from the 1970s, particularly in OECD countries because of their strict enforcement of environmental laws. Equipment for cleaning the flue gas from PC boilers has been historically considered as 'add-ons' – wherein only the boiler and steam turbine were considered as essential technologies. However, pollution reducing equipments, such as low NOx burner, electro-static precipitator (ESP), flue gas desulfurizer (FGD), and selective catalytic reducer (SCR), are now often considered to be part of the standard PC technology packages. With these add-on pollution control, PC power plants now have relatively low emission rates: NO_x – 50-100 mg/Nm^3, SO_2 – 75-100 mg/Nm^3, and particulates below 10-20 mg/Nm^3 (PowerClean, 2004).[305] However, these low emissions from PC plants are still above emissions from NGCC power plants, which have practically no SO_x and particulate emissions. Furthermore, multi-pollutant control systems can

[303] Fuel oil is used in PC plants routinely for startup operations (known as secondary oil consumption).
[304] Although the thermal efficiency reduction is only 8-9%, coal consumption per kWh increases inversely in proportion to coal quality. For ultra-supercritical plants, the similar loss in thermal efficiency is higher at about 11% (Khan et al., 2005).
[305] Japan has some of the cleanest PC plants in the world. For example, the 2001 Hekinan (2 x 1000 MW) plant achieves particulate emissions of 5 mg/Nm^3 and NOx emissions of 30 mg/Nm^3. The very low particulate emission results from the use of a cold ESP (PowerClean, 2004).

economically integrate the capture of multiple pollutants with a simpler design and fewer moving parts. Such multi-pollutant control systems would be relevant in countries with effective regulation for all pollutants. However, in developing countries, where environmental laws and their enforcement have been historically weak, emissions from PC power plants remain high, as the post-combustion pollution control technologies are always included as part of the standard design for PC plants. Moreover, the use of low quality coals decreases efficiency and adds to the pollution load in these countries. In India, for example, the use of high-ash coals increases ash production and there are significant problems with utilizing the ash, unlike in the OECD countries where most of the ash generated by PC plants is constructively utilized.

The technology and market risks associated with advanced PC technologies are generally lower, because these mostly are mature, commercial technologies and their costs are well understood. The capital cost of the supercritical technology is well known, which is generally 3-10% more expensive than sub-critical units, depending on site-specific factors (DTI, 1999). However, actual cost-estimates are highly dependent on various assumptions (as discussed later in section 7.1), with estimates being different in different countries and across different points in time. For example, the IEA (1998) estimated that a 600 MW power plant with ESP and low-NO_x burners in an OECD location would have a total plant cost of about $800/kW, $810/kW, and $810/kW for subcritical, supercritical, ultra-supercritical units, respectively.[306] The higher costs for the boiler, turbine and related accessories for super and ultra-super critical units were offset by the increased efficiency and the reduced cost for coal handling systems, pulverizers, precipitators, etc. (IEA, 1998). However, recent estimates by Alstom for a supercritical power plant built today in the United States have EPC costs[307] ranging from $1140/kW to 1200/kW[308] depending on the steam parameters (Palkes et al., 2004).[309]

Another important part of the total cost of a PC plant is the cost of pollution control devices. The IEA (1998) has estimated that adding FGD and SCR (often considered optional in developing countries) to advanced PC plants would add about 17% to the base capital cost. The price of wet FGD systems has been steadily decreasing with increased use (costs have dropped by about 50% from the late 1980s), and the auxiliary power consumption has also been reduced (Kitto, 1996). Furthermore, increased efficiency of advanced supercritical PC systems will reduce the sizes of pollution control devices, which could further reduce the cost of pollution control devices.

Current RD&D in PC technology is focused on developing improved materials (steel alloys[310]) that can withstand high temperatures and pressures. Steam temperatures and net efficiencies have been increasing steadily in recent years (see Figure 40), and it is expected that with new

[306] Land, development, financing and owners costs are not included. Similar plants in China would have cost around $620/kW (IEA, 1998).
[307] EPC costs include engineering, procurement and construction costs. It is also generally known overnight capital cost or total plant cost. It does not include owner's cost and interest during construction.
[308] Based on 2004 U.S. dollars.
[309] Construction costs of power plants have increased dramatically in the United States over the last couple of years because of high labor costs and increased demand for steel and other materials. Therefore, more recent cost estimates will be higher.
[310] Some of the newer steels include stronger alloys of chromium and molybdenum, and nickel-based alloys.

materials and designs,[311] the net efficiency of PC-based power plants can reach close to 50% (LHV) around 2010; see Figure 41. Much of the advanced steel development has been focused in Europe and Japan, with some recent R&D efforts in the United States. The 'AD-700' project in Europe (part of EC-THERMIE R&D program) aims to develop and demonstrate a new generation of ultra-supercritical plants with steam parameters of 700/720°C, 375 bar, leading to LHV efficiencies of 52-55% (PowerClean, 2004).312 The United States, which lost its initial lead in the supercritical technology, has been supporting an advanced materials program aimed at USCPC technologies. The USDOE/NETL program involved U.S. boiler manufacturers such as Alstom, Babcock Borsig, Babcock & Wilcox/McDermott, and Foster Wheeler. There is also an active R&D program in advanced steels in Japan, supported by the Japanese government.

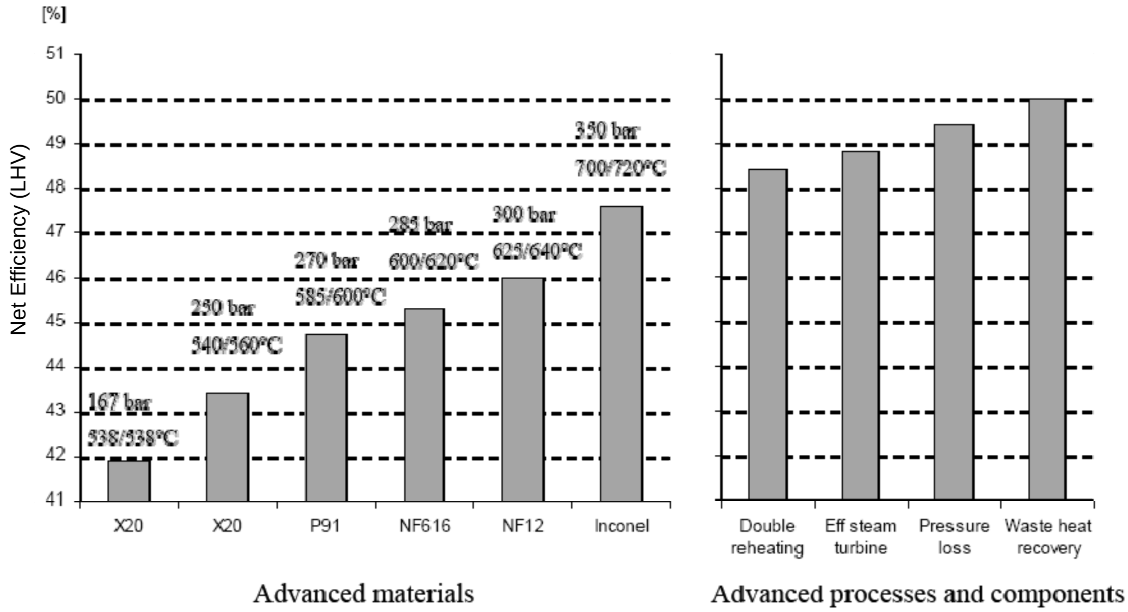

Figure 41: Potential net efficiency improvements for supercritical PC plants. The names of advanced steel alloys along with the resultant increase in steam parameters and efficiency is shown on the left. These new materials can be combined with advanced processes and components to generate electricity with high efficiency in PC plants. New efficiency of 50% (LHV) net efficiency is expected to be reached around 2010. Currently, the best PC plants have net efficiency of about 47-48% (LHV). However, it has to be noted that European plants tend to have higher efficiency because of colder air and water temperatures; see section 7.1. Source: (Lako, 2004).

6.1.1 Supercritical PC in India

As discussed earlier in section 2.4.5.1, supercritical PC technology is being deployed in India –a 3x660 MW power plant is under construction at Sipat, and another one at Barh has reached financial closure. While this nascent development is heartening, it certainly does not meet the CEA's expectations of the power sector being well on its way to installing 8-10 supercritical units (CEA, 2003).

[311] High-strength ferritic steel, austenitic steel with chromium, molybdenum and vanadium alloys, Inconel steels (chromium and nickel alloys), and various other steel alloys are now being used in boilers.[311] Steam turbines for utilizing ultra-supercritical steam are being designed using advanced computational fluid dynamics software, utilizing matensitic and ferritic steels (Kitto, 1996; DTI, 2002; Lako, 2004).
[312] Another European program that aims at development of advanced PC technologies is the COST program.

Unlike with the 500 MW subcritical units, NTPC has relied on foreign technology for supercritical PC, rather than going with BHEL's licensed technology.[313] Some have felt that BHEL has been purposefully disregarded in favor of foreign companies (Kumar, 2005; Purkayastha, 2005). Given BHEL's experience with adapting PC technology to utilizing high-ash content Indian coals, and making further improvements, one might have expected BHEL to take the next steps and develop supercritical technology on its own, rather than rely on another new license.[314] Instead, BHEL has focused on tying-up with international manufacturers to license supercritical technology for manufacture.[315] However, there is little operating experience in the international market for running supercritical power plants using high-ash-content coal.[316] Recently, Alstom and BHEL have announced an industrial partnership agreement whereby Alstom will license its once-through boiler and pulverizer technologies to BHEL. Alstom will provide engineering/design support and supply certain key components of the boilers and BHEL will manufacture boilers (Alstom, 2005b).[317] The new agreement might allow BHEL to compete with international manufacturers for providing supercritical units in India.

In terms of performance, supercritical PC plants with FGD are expected to improve thermal efficiency by about 5%, compared with the standard subcritical PC technology without FGD. Use of washed coal, instead of run-of-mine coal, can further improve the efficiency of supercritical units by about 1% (Nexant, 2003). In terms of cost, Nexant (2003) has indicated that supercritical PC would cost only about 7% more than sub-critical PC. However, adding a FGD to PC plants can increase the total plant cost significantly. Based on Nexant (2003) estimates, adding a FGD to subcritical power plant will likely increase the total plant cost (without IDC) by 24% when compared with a conventional subcritical power plant in India;[318] the cost of a supercritical plant with FGD would be about 32% more than that of a conventional sub-critical PC plant.

---

[313] As mentioned in section 2.4.5.1, the boilers and turbine-generators for the Sipat power plant has been ordered from the Korean Doosan Group and Power Machines Russia, respectively. The Barh power plant is to be entirely based on Russian technology (Technopromoexport and Power Machines Russia).

[314] It is possible that the limited market opportunities for supercritical power plants in India and limited investment in material science led BHEL to focus on mastering the sub-critical PC technology, rather than developing supercritical technology on its own (Personal Communication, NETL official, January 2006).

[315] BHEL had an initial technology collaboration with Babcock Borsig for supercritical boilers; however, this collaboration died when Babcock Borsig went bankrupt (Ramesh, 2004). Since then, BHEL tied-up with Alstom for supercritical boilers to bid for NTPC's Sipat power plant; however, Alstom has maintained that certain key technologies have to be bought directly from Alstom rather than being manufactured by BHEL (Ramesh, 2005).

[316] It should be noted, though, that two subcritical 500 MW units at the NTPC's Talcher power plant has been operating boilers with once-through technology since the mid 90's (TERI, 2001), and some South African power plants also operate boilers with once-through technology using high ash-content (35%) coals (Paul, 1999).

[317] Alstom is also expected to train BHEL engineers and support them "in the design, engineering, manufacturing, assembly, testing, erection, commissioning, repair, retrofit and upgradation of the boilers" (BHEL, 2005b).

[318] Ghosh (2005) has noted that the addition of FGD will add about $180/kW to the cost of a subcritical plant, consistent with the Nexant analysis.

6.2 *Fluidized-bed combustion (FBC)*

Unlike pulverized coal, fluidized-bed boilers can combust larger pieces of coal (sized to about 3 mm) by creating a combustion-zone bed using pressurized air. The coal bed becomes fluidized (suspended) when the air flow is strong enough to match the bed's weight (DTI, 2000a). With enough air flow into the bed, the bed particles get agitated and well-mixed, resulting in a uniform combustion temperature along the bed. Similar to pulverized-coal boilers, this heat is then used to convert water into steam.

There are several benefits to FBC technology in comparison to pulverized coal (Kavidass et al., 2000):

- lower costs due to reduced crushing of coal,
- ability to burn a wide variety of coals including low-quality coals, waste coal, biomass and other feedstock,
- in-combustion sulfur removal by mixing crushed limestone/dolomite along with coal,
- reduced NOx production due to lower combustion temperature (800-900 ^{o}C), and
- lower overall cost in comparison to PC with FGD and SCR systems.

A key disadvantage of FBC in comparison to PC is the increased production of solid waste, not only because of use of lower quality feedstock, but also because of the sorbents added to the combustion reaction. In some cases, the resulting solid waste can also be used as construction material, cement manufacturing, structural fills, etc. (Kavidass et al., 2000).[319] Secondly, although NO_x emissions are reduced due to lower temperatures, there are increased emissions of N_2O – a powerful greenhouse gas – which, however, can be reduced in several ways (Ghosh, 2005). Also, fluidized bed burners are sensitive to changes in feed quality, although they are able to use lower quality coals than PC boilers; and if the quality of feedstock is highly variable, it may not be possible to use this for power generation (Frankland, 2000).

There are several variants of FBC systems: bubbling, circulating, and pressurized FBC systems. For utility-scale power generation, circulating and pressurized systems are more important.

6.2.1 Bubbling fluidized-bed combustion (BFBC)

In a BFBC boiler, the air flow into the bed is strong enough for fluidization, but not large enough for a continuous outflow of fine particles. The coal in the bed is gradually combusted, with fine particles escaping out in the flue gas as fly ash. As with the PC boiler, heat exchangers extract heat from the flue gas before the clean-up stage.

Generally, the unit size of BFBC boilers are small-to-medium scale (30-300 MW_{th}), and they are used mainly in industries – particularly in the pulp and paper industry for generating steam.[320] BFBC technology is quite mature with a wide variety of local and international manufacturers, and so there is little prospect for dramatic improvements in the technology. Future market for

[319] Depending on feedstock used for the FBC, control of heavy metal leaching from the solid wastes might be required.
[320] However, increased use of natural gas in industrial applications has reduced the use of BFBC boilers.

the technology might be limited to India and China, where industrial use of coal is still quite prevalent (DTI, 2000a).

6.2.2 Circulating fluidized-bed combustion (CFBC)

In a CFBC boiler, air is blown into the bed with enough pressure to elutriate fine particles out of the bed. Unlike in a BFBC boiler, there is no distinct boundary between the bed and the flue gas in the boiler. Rather, the fine particles that elutriate out with the flue gas are captured in a cyclone and recirculated back into the bed – thereby increasing boiler efficiency by increasing the residence time of coal in the boiler. Similar to BFBC, combustion takes places at atmospheric pressure. About 90-95% of the SO_x produced can chemically react with sorbents such as limestone and dolomite added into the bed. NO_x emissions are also reduced by controlling bed temperature and emissions less than 100 ppm can be achieved (Kavidass et al., 2000). Hence, CFBC technology has been the preferred technology for utility-scale electricity generation.

CFBC is a mature technology with more 1000 units installed worldwide with a total capacity greater than 65 GW_{th}, with more than 50% of these units being installed in Asia (DTI, 2000a). Generally, unit sizes range between 30 to 400 MW, with several hundred units in the 250-300 MW range. The technology, although developed only in the late 1970s, has proven its reliability. Some of the key companies involved in technology development include Alstom, Babcock and Wilcox, Foster-Wheeler, and Mitsui-Babcock.

The ease of operation that comes with the opportunistic ability of CFBC to use a wide variety of coals, combined with the many number of world-wide manufacturers, have helped to sustain this technology. The technology is also relatively simple, without the need for pulverizers or many add-on pollution control devices, that small CFBC plants can be installed relatively quickly (DTI, 2000a). There are opportunities for retrofitting CFBC technology on old PC plants as well to take advantage of the CFBC's fuel-flexibility. Studies have indicated that the repowering PC plants with CFBC can be economically viable by using low-grade (cheap) fuel, eliminating pulverizers, and reducing auxiliary power consumption (Kavidass et al., 1999).

The efficiency of CFBC units mostly is comparable to equivalent PC units, although they may be 3-4 percentage points lower than equivalent PC in the 100-200 MW range. The use of low-grade coal combined with heat lost in the cyclone and by the removal of ash and spent sorbent, leads to some loss of efficiency (IEA, 2005a). Furthermore, the use of subcritical steam cycle limits the overall thermal efficiency; although there are plans to develop advanced supercritical-based CFBC technology to increase efficiency. The 460 MW Lagisza plant in Poland (currently under construction) is expected to be the first supercritical CFBC power plant, with efficiency greater than 41% HHV (Power Technology, 2005).[321]

CFBC-based power plants can have lower overall costs in comparison to PC-based systems. Although the capital cost for CFBC can be higher by 5-10% in comparison to a PC plant without pollution control devices for SO_x and NO_x, the costs can be 8-15 % can lower than a PC system with FGD and SCR. Operating costs can also be 5-10% lower than PC plants, especially in units

---

[321] Foster-Wheeler, which built the first CFBC-based plant for power generation in 1979, is building the Lagisza plant, which is expected to commence operations in 2006 (Power Technology, 2005).

less than 150 MW (Ghosh, 2005). Finally, fuel costs for a CFBC plant are lower not only because of the use of lower rank coal, but also because CFBC's fuel flexibility allows the use of a wider range of feedstock.

Future government RD^3 support for the development of CFBC technology is somewhat limited in the major developed countries. The United States ended its RD^3 support for the CFBC technology in the early 1990s, although it played an important role at the initial stages of technology development in the 60s and 70s (Ghosh, 2005). U.S. RD^3 supported various demonstration plants that focused on emission reduction and technology scale-up. Although the market in the United States is rather limited for the CFBC technology,[322] the lessons from the demonstration plants will be useful for future technology development. The EU has also supported CFBC demonstration plants in Spain and France. Although the European Commission does not plan on future support, Electricité de France (EdF) is investing in CFBC R&D with focus on scale-up and fluid dynamics modeling (DTI, 2000a).

6.2.3 Pressurized Fluidized-bed Combustion (PFBC)

In contrast to CFBC and BFBC, where combustion takes place at atmospheric pressure, the boiler and cyclone of a PFBC system are placed in a pressurized chamber, so that combustion can take place under high pressure. The underlying combustion process for the PFBC can be based on either bubbling or circulating fluidized-bed systems, although most of PFBC systems have been based on the bubbling-bed technology. Pressures of 12-16 bars can be reached with temperatures in the range of 800-900 ^{o}C (IEA, 2005a). The high-pressure hot flue gas from combustion process is then cleaned and expanded in a gas turbine, allowing for a combined cycle operation. Generally, the gas turbine accounts for 20% and the steam turbine 80%, of the total electricity generation. The environmental performance of PFBC is similar to other FBC systems, except for the increased efficiency.

The key advantage of PFBC is the increased efficiency that results from both the pressurized combustion and the combined cycle operation. The efficiency of PFBC is higher than of CFBC, and it can reach as high as 40% (Ghosh, 2005). Advanced PFBC (APFBC) systems add a carbonizer before the PFBC boiler to generate fuel gas and char. The char is sent to the PFBC boiler and the fuel gas is cleaned and burned in a topping combustor. The vitiated flue gas from the PFBC boiler and from the topping combustor is then sent into the gas turbine for power generation. The efficiency of such advanced systems can be as high as 47% (Ghosh, 2005). In fact, the most advanced Karita supercritical PFBC plant in Japan (360 MW) already has a net efficiency of 42% HHV (PowerClean, 2004).

Key disadvantages of the PFBC technology include: the need to pressurize the input feedstock and sorbents, depressurize the ash and spent sorbent, and the complexities associated with the pressure vehicle. While the APFBC is more efficient compared to PFBC, its combined cycle operation is not as efficient as that in the case of NGCC or IGCC. Furthermore, the advanced-PFBC systems with a topping combustor add to the complexity of the system. Rather than partially carbonizing the coal, it might be better to gasify it completely, as in an IGCC.

[322] U.S.-based CFBC plants might focus on the use of waste coal and other feedstock. For example, the 2x250 MW Seward power plant in Pennsylvania uses waste coal to generate electricity. It is currently the largest CFBC plant in the world to use waste coal as a feedstock.

However, one should note that APFBC plants can utilize a wide range of coal, including low-grade coals, but IGCC requires relatively better grades of coal (as discussed later).

There have been about five 80 MW PFBC demonstration plants in the U.S.,[323] Europe, and Japan using the technology developed by Sweden's ABB Carbon, which is now part of Alstom Sweden (ATLAS, 2005; IEA, 2005a).[324] Other suppliers are Ahlstrom in Finland, Lurgi-Lentjes-Babcock in Germany, and Ebara, Hitachi and Mitsubishi in Japan (Ghosh, 2005). These demonstration plants indicated several problems in the clean up of the hot gas, high erosion in the heat exchanger, and overheating of the bed due to agglomeration (Anthony, 2003). While these problems could be solved, funding for technology development has reduced. In the United States, several future PFBC and advanced-PFBC demonstration plants have been cancelled (Ghosh, 2005). Alstom is no longer supporting the technology, as competition from IGCC, NGCC and supercritical PC technologies has reduced interest in PFBC (Anthony, 2003). Although there is still some research activity supported by the U.S. and E.U., it is becoming increasingly clear that future development of this technology is reliant primarily on efforts by Japan,[325] and possibly China.

6.2.4 FBC in India

It is estimated that more than 200 BFBC boilers are in use in India (DTI, 2000a). BHEL developed its own BFBC technology using in-house R&D, with technical assistance by USAID (Smouse, 2003). More than 50 boilers using BHEL technology have been contracted with capacities ranging from 1.5 ton/hr to 165 ton/hr. These boilers were also designed to use a variety of fuels including coal, lignite, washery rejects, coal fines, kiln waste, ESP dust, biomass (rice straw, rice husk, palm wastes), oil sludge, paper sludge, municipal solid waste, etc. (Gopinath et al., 2002; BHEL, 2005c).

As discussed earlier in section 2.4.5.2, CFBC is the only utility-scale coal power technology other than PC that has been successfully operated in the India at a commercial level. BHEL licensed the CFBC technology from Lurgis Lentjes Energietechnik Gmbh (LLB) of Germany (Gopinath et al., 2002). The first utility scale CFBC boilers (2x125 MW) using lignite were commissioned in 2000 at the Surat Lignite Power Plant, and are operating successfully. Despite the high ash content in Indian coal, CFBC is mainly being considered for use with lignite, coal-washery middling and other waste coal.[326] In addition to BHEL, Alstom is also installing utility-scale CFBC boilers in India. Petcoke has also been recently used in industrial-scale CFBC boilers. A petcoke-based 25 MW CFBC boiler from Foster-Wheeler has been operating since 1999 at Rain Calcining Limited, in Andhra Pradesh.[327] A larger scale-up of CFBC boilers (2 x 250 MW) using petcoke from Reliance Industries refineries is planned at Jamnagar (Bhuskute and Ambhaikar, 2002).

---

[323] For details on the U.S. demonstration plant at Tidd, see: Ghosh 2005 and NETL website: http://www.netl.doe.gov/technologies/coalpower/cctc/cctdp/bibliography/demonstration/aepg/baepgfb_tidd.html.
[324] ABB's PFBC technology was licensed by various manufacturers such as Babcock & Wilcox in the United States and Ishikawajima Heavy Industries (IHI) in Japan (ATLAS, 2005; IEA, 2005a).
[325] Japan has two large-scale PFBC plants in operation – Karita (360 MW) using supercritical steam conditions and Osaki (250 MW).
[326] Interview with BHEL officials (February 2005).
[327] See: Foster Wheeler update, Spring 1999. http://www.fwc.com/pow_services/fluidize/newsletter/fw_spring.pdf; (Bhuskute and Ambhaikar, 2002)

In terms of PFBC, technology development for India has been limited to R&D activities by BHEL. A small scale (6 ton/hr) PFBC testing facility was setup and operated by BHEL R&D using a wide variety of feedstock. Using this test facility, feasibility studies for scale-up were conducted; however, the lack of commercial gas-cleanup technology has prevented further development of this technology (Gopinath et al., 2002). It is clear that any further development of this technology in India requires a great deal of investment and linkages with Japanese technology developers, who are the only ones investing in any significant R&D in this area.

6.3 Oxyfuel Combustion

Standard coal combustion uses air (with 21% oxygen) as the oxidizing agent. However, coal can also be combusted using pure oxygen, instead of air: hence, the term "oxyfuel" combustion. By eliminating nitrogen flow, the flue gas volume in oxyfuel-PC can be reduced by 70% in comparison to standard PC, with CO_2 concentrations between 80-98%, after extracting the water out of the flue gas. (Farzan et al., 2005; IPCC, 2005). Such high CO_2 concentration in the flue gas can be a significant advantage for CO_2 capture from power plants, where the dry CO_2-rich flue gas can be sequestered, with or without further purification. Therefore, oxyfuel combustion technologies are likely to be relevant when considering capture of CO_2 from power plants (see section 6.6 for details on CO_2 capture technologies).

The reduced flue gas volume also results in overall smaller equipment, including a smaller overall size of the boiler and a simpler flue-gas purification scheme, which can significantly reduce capital and operating costs (IPCC, 2005). The elimination of nitrogen and oxygen-enrichment in the boiler significantly reduces the production of NO_x,[328] perhaps eliminating the need for special NO_x cleanup systems.

Burning coal using pure oxygen, however, leads to very high temperatures (~ 3500^{o}C) that cannot be handled by standard boiler material. Thus, in practical terms, oxyfuel combustion refers to technology where coal is burned with a mixture of oxygen and recycled flue gas (with mainly CO_2) to maintain similar oxygen proportion as air-blown boilers. In such systems, the flame temperature becomes comparable to that in standard air-blown boilers, but the flue-gas is rich in CO_2, maintaining the advantage of easy separation. Oxyfuel-based combustion can be used in coal-based PC and FBC technologies and in natural gas-based power plants.

However, a key disadvantage for oxyfuel combustion is the need for pure oxygen (about 3 times more pure oxygen compared to IGCC), which at present is very expensive. The standard technology for air separation is based on cryogenic techniques, which consumes enormous power[329] – leading to increased auxiliary consumption. Hence, oxyfuel-based technologies will become relevant and competitive with PC- and IGCC-based CO_2 capture from power plants only when carbon capture and storage becomes an important issue for power plants. Current cost estimates for new power plants indicate that oxyfuel and carbon capture for a new PC power plant results in a 50% increase in the specific capital cost; similarly, a 90% cost increase results for oxyfuel CFBC plant with carbon capture (Marion et al., 2003; Dillon et al., 2004).

While the technology's potential for carbon capture is quite promising, it is only at the early demonstration stage. Pilot-scale demonstration plants are being planned in Europe, Australia and Canada. Along with power manufacturers, such as Alstom, Babcock &Wilcox, Foster-Wheeler, and Mitsui-Babcock, many manufacturers of oxygen using cryogenic and membrane-based air separators, such as Praxair and Air Liquide, are very interested in promoting this technology.

[328] Air Liquide and B&W estimate a 65% reduction in NO_x production in their pilot-scale oxyfuel test facility (Farzan et al., 2005).
[329] Using cryogenic distillation, about 200 kWh is consumed to produce one ton of oxygen at atmospheric pressure for a coal-based oxyfuel plant (IPCC, 2005).

Alstom and Foster-Wheeler are also interested in oxyfuel-based CFBC, in addition to oxyfuel-PC technologies.

Oxyfuel combustion technology can be retrofitted on existing PC or CFBC power plants. If carbon capture from power plants becomes necessary in the future,[330] existing efficient power plants can be converted to oxyfuel combustion by adding an oxygen production plant along with a carbon capture facilities. The net efficiency and net output will be reduced upon such retrofitting. The IPCC (2005) has noted that "the concept of retrofitting oxy-fuel combustion with CO_2 capture to existing coal-fired power stations does not have any technical barriers and can make use of existing technology systems." This retrofitting option might only be cost-effective if used in a highly efficient power plant, but nonetheless offers a possible route to meeting the carbon mitigation challenge.

Finally, it is expected that with advanced air separation technologies using high-temperature oxygen-ion transport membranes[331] will reduce air separation costs – making oxyfuel combustion more competitive with other technologies for carbon capture (Gupta et al., 2005). Other advanced techniques such as chemical looping combustion are also in the offing. These advanced technologies enhance the future prospects for oxyfuel combustion.

[330] Carbon capture from power plants might become necessary if India signs on to a strict regulation of carbon emissions as part of a broad international agreement on mitigating carbon emissions.
[331] These membranes are ceramics made from a mixture of various metal oxides.

6.4 Integrated Gasification Combined Cycle (IGCC)

After combustion, gasification is the next most important pathway for utilizing coal for electricity generation. The gasification process involves pyrolyzing coal and partially oxidizing it using oxygen (or air) and steam to produce a high-energy gas – usually referred to as synthetic gas or syngas. Gasification of coal is almost 200 years old -- coal gas was used to light street lamps in 1807 in London and in Baltimore by 1816 (Bonk, 2005). But, its application for generating electricity began only in the 1960s with technology initially developed by Germany during World War II for producing liquids fuels (NRC, 1995). For power plant operations, the syngas, which is composed primarily of carbon monoxide (CO) and hydrogen (H_2), is produced under pressure, water-cooled, cleaned, and burned in a gas turbine. The steam produced from the heat exchanger (used to cool the syngas) is used to produce power with an integrated steam turbine in combined cycle operation[332] – hence the term "integrated gasification combined cycle (IGCC)." In addition to the steam cycle integration, compressed air (obtained from a compressor running off the gas turbine shaft) can also be integrated with the air separation unit that produces the required oxygen. Essentially, there are two main sections to an IGCC – the gasifier island and the combined cycle power island. In effect, IGCC is a hybrid between the traditional coal-combustion-powered steam-based electricity generation and the natural-gas-based combined cycle electricity generation.

The syngas produced from gasification can also be used as a feedstock to make chemicals, such as ammonia, methanol, hydrogen, etc. These chemicals can then used to make fertilizers, transportation fuels, plastics, etc. Such an application of gasification is a commercial technology, whereas the use of syngas to generate electricity in an IGCC operation is rather new. There is also the possibility for using the syngas to create multiple products – chemicals, hydrogen and electricity – a process that is termed "polygeneration". A significant advantage with gasification is its ability to gasify a wide range of fuels – theoretically, any solid or liquid carbon source can gasified, including petroleum-coke, refinery residues, biomass and municipal solid waste.

In comparison to combustion-based technologies, advantages of IGCC include:

- increased efficiency from the combined cycle,
- improved environmental performance,
- lower cost of cleanup technologies,[333]
- greater ease of carbon capture, and
- lower incremental cost of capture at present.

Some of the disadvantages are:

- high degree of complexity – IGCC is more like a chemical plant than a power plant,
- higher capital costs,
- problems with reliability and availability, and
- low technology maturity (and therefore greater perception of technology risk).

[332] Generally, the proportion of power from steam to gas turbines is about 40:60% (IEA, 2005a).
[333] The cost of cleanup technologies is lower in an IGCC because of the smaller volume of syngas to be cleaned, in contrast to cleaning up of flue gases from PC plants.

Despite these disadvantages, IGCC is considered as an important technology for the future, since it is expected that greater emphasis will be placed on high efficiency and emission-free production of electricity as local and global environmental constraints become more pressing.

Emissions from an IGCC plant are lower than combustion-based PC plants. IGCC essentially has no particulate emissions, since almost all of the particulates have to be removed before the syngas enters the gas turbine. Unlike in a PC plant, gas cleaning is part of the process, rather than an "add-on". Using the metric of mass emissions per energy content of input (e.g. lbs/MMBTU or g/kcal), it is expected that U.S. IGCC plants are expected to emit about 3-5 times less SO_2 than PC plants with FGD and 2-3 times less NO_x than PC plants with SCR (Khan et al., 2005). IGCC also uses at least 70% less water than standard PC plants (Khan et al., 2005). Hence, the environmental performance of IGCC plants can be quite close to NGCC plants, despite using coal. Similar to the PC plants, the overall efficiency of IGCC is dependent on coal quality (Booras and Holt, 2004); a U.S. EPA study suggests a drop of three percentage points in efficiency for IGCC using lignite instead of bituminous coals (Khan et al., 2005).

Furthermore, oxygen-based IGCC plants are expected to have a lower cost of generated electricity when capture of carbon is required, as opposed to capture of CO_2 from the flue gas of PC plants because of higher concentration and partial pressure. By using a shift-reactor[334] in an IGCC, the carbon in the syngas can be converted into a pure stream of CO_2 that can be captured and sequestered. The carbon capture in this case occurs before combustion of the syngas – 'pre-combustion capture' – unlike in PC plants, where carbon capture must occur post-combustion.

Broadly, gasification processes can be divided into air-blown and oxygen-blown gasification. Most gasification processes use oxygen as an oxidant, although air-blown gasifier systems are simpler and possibly cheaper. Air-blown gasifiers are larger since they have to handle large nitrogen volumes. While air-blown gasifiers are not considered at present for commercial power applications[335] because of its compatibility with carbon capture, there is still ongoing research in this area. Air-blown IGCC might still be considered if the IGCC's local environmental benefits are highly valued.[336] In contrast, gasification of coal using oxygen reduces the size of the gasifier and it is more amenable to carbon capture. However, the requirement of an air-separation unit (ASU) for oxygen production raises the total plant cost and the power plant's auxiliary consumption. In addition, further integration is possible for oxygen-blown systems, wherein the ASU can be integrated with a compressor powered by the gas turbine. Given these advantages, most of the planned IGCCs world-wide are based on oxygen-blown gasifiers.

There are three main types of gasifiers: moving-bed gasifier, fluidized-bed gasifier, and entrained-flow gasifiers. These gasification processes are illustrated in Figure 42 and some of the basic characteristics of these gasifies are listed in Table 30. It is important to note that

[334] The water-gas shift reaction is $CO + H_2O \rightarrow CO_2 + H_2$.
[335] An exception is the Japanese Clean Coal Technology Roadmap, which plans for future demonstration of air-blown IGCC technologies (Kashiwagi et al., 2004; IEA, 2005a).
[336] The USAID-Nexant (2003) study notes that current plans for demonstration of IGCC in India is motivated primarily by its environmental benefits such as low water consumption and low emissions, rather than any carbon benefits.

worldwide IGCC experience and information is primarily based on entrained-flow gasifiers, since there are very few large-scale IGCC systems using fluidized-bed and moving-bed gasifiers.

Reactor Type	**Moving-bed**	**Fluidized-bed**	**Entrained-flow**
Combustion analogy	grate fired	FBC	PC
Coal Feed	Dry	Dry	Dry or Slurry
Coal Size	< 50 mm	< 6 mm	Fine dust (<500 μm)
Fuel residence time	15 -30 minutes	5-50 seconds	1-10 seconds
Oxidant	air or oxygen	air or oxygen	primarily oxygen
Syngas temperature at exit [^{o}C]	340-650	700-1050	900-1500
Cold Gas Efficiency	High	Medium	Low
Ash	Dry or Slagging	Dry or Agglomeration	Slagging
Major Gasifier types/manufacturers Oxygen-blown	British Gas Lurgi, Sasol, Lurgi	HT Winker, Foster Wheeler, KRW	Slurry: GE-Texaco, Conoco-Phillips E-GAS; Dry: Shell, Prenflo, Noell
Major Gasifier types/manufacturers Air-blown	Lurgi	HT Winker, Foster Wheeler, U-GAS, KRW, MBEL	Mitsubishi
Ability to use Indian coal	Yes	Yes	No

Table 30: Characteristics of Coal Gasifiers. Adapted from (Qureshi, 2001; Nexant, 2003; Bonk, 2005)**.**

Box 3: IGCC vs. Oxyfuel

It is instructive to compare IGCC with oxy-fuel combustion. Both processes require an ASU for oxygen production, however, combustion in a boiler requires about three times as much oxygen as gasification, and so, the ASU cost will be much higher for oxyfuel combustion. However, unlike gasification, oxyfuel combustion might not require high-purity oxygen, which might lower costs. Furthermore, nitrogen is not useful in oxyfuel combustion and venting it will reduce the overall efficiency of oxyfuel combustion, unlike in IGCC where the separated nitrogen can be integrated into the air-flow of the gas turbine for NO_x control and for pressurizing lock-hoppers.

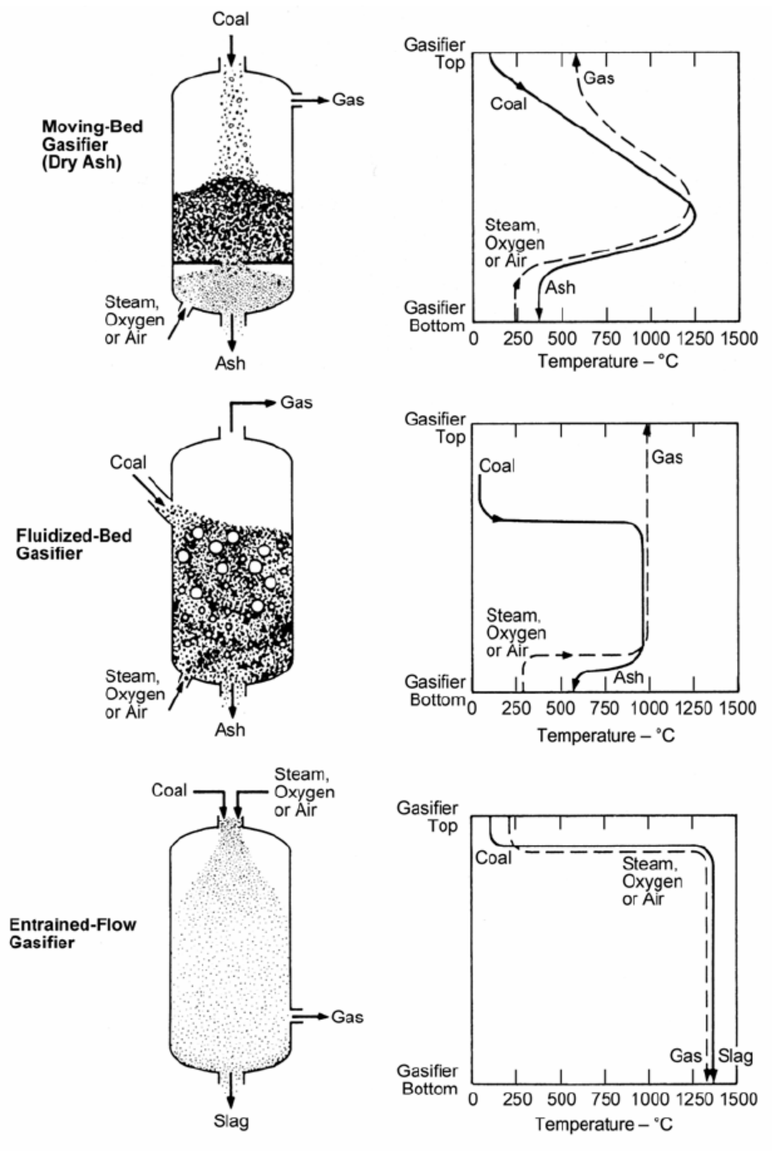

Figure 42: The three major gasification processes are illustrated with the temperature and flow directions of coal, oxidant and ash/slag flow being indicated on the right. Adapted from (Holt, 2004b).

6.4.1 Entrained-flow gasifier

The slagging, entrained-flow gasifier is the most commonly used gasifier for power generation today. The gasifier allows for high uniform temperatures and low fuel residence time (see Figure 42). Similar to pulverized coal, feedstock must be finely powdered and it can be injected under pressure into the gasifier either in a dry form or as a slurry using water. Entrained gasifiers are more compatible with liquid fuels such as refinery residues rather than biomass or high-ash coals, which cannot be pulverized as easily (DTI, 1998). The process has relatively low cold-gas efficiency, requiring high oxygen input (Bonk, 2005). Moreover, coal ash is generally removed from the gasifier as molten slag, which occurs because of the high temperature in the gasifier and the low ash-fusion temperature of the input feedstock. Hence, this type of gasifier is not compatible with Indian coals, which have both high ash content and high ash fusion temperature.[337]

Entrained-flow gasifiers are commercially available, and there has been significant experience with IGCC using entrained-flow gasifiers. Over the last 20 years, entrained-flow gasifiers have been selected for most of the large-scale commercial coal- and oil-based gasification to produce chemicals and/or electricity (DTI, 1998; IPCC, 2005). Some of the major oil and chemical companies, such as Texaco[338], Dow[339], Shell, etc., have invested in developing entrained-flow gasification technology for both oil and coal-based feedstock in the United States and Europe. There are several demonstration and pre-commercial IGCC plants in operation in the United States, Canada, Europe, Australia, Japan and China.[340] Some of the important IGCC demonstration plants using entrained-flow gasifiers include:

- 250 MW Tampa Electric power plant (Texaco gasifier)
- 262 MW Wabash River power plant (E-GAS gasifier)
- 250 MW Buggenum power plant (Shell gasifier)
- 300 MW Puertollano power plant (Prenflo gasifier)

The demonstration plants in Europe and U.S. have operated with efficiencies ranging between 38-43% HHV (Lako, 2004). Other studies have indicated that IGCC with entrained-flow gasifiers can have efficiencies in the range of 35-40% (HHV).[341] It is expected that the efficiency of IGCC technology will improve significantly with increasing operational experience. R&D efforts to improve gas turbines, hot-gas-cleanup systems, and materials technologies are expected to increase efficiency of IGCC plants to 45-50% HHV by 2010-2015, and further to 50-60% HHV by 2015-2025 (CETC, 2005).

In addition to high efficiency, all of the environmental benefits discussed earlier apply to entrained-flow gasifiers. Sulfur is removed from the syngas either as pure sulfur using a MDEA/Claus/SCOT process or as sulfuric acid using sulfuric acid removal plants. The sulfur by-products can then be sold for industrial use. Ash in an entrained gasifier is removed as a glassy slag – with less than 50% of coal-ash being removed as fly ash. The slag can then be used for road bases, landfills, specialized cements, and dental and biomedical applications. The slag might also be used for mercury removal and NO_x adsorption (IEA, 2004d).

Despite these benefits, the biggest downside to entrained-flow gasifier IGCC is its higher cost in comparison to traditional, or even advanced, PC systems. The capital cost is generally 20-30% higher than advanced PC – ranging from \$1200 - \$1600/kW.[342] The cost estimates of IGCC plants vary widely not only because of different assumptions made by different analysts,[343] but

[337] However, it might be possible to inject fluxing agents to reduce the ash-fusion temperature of Indian coals (PowerClean, 2004), allowing the possibility of using entrained flow gasifiers with Indian coal.
[338] Texaco gasifier technology is now owned by GE.
[339] Dow gasifier technology (called the Destec process) is now owned by Conoco-Phillips and it is called as E-GAS technology.
[340] See World Gasification Database: http://www.netl.doe.gov/coal/gasification/database/database.html.
[341] The wide range of efficiencies results from various analysis that use different gasifiers, operating under varied conditions. See Table 37 for references.
[342] In 2004 dollars; see Table 37 for references.
[343] For example, see Table 2.3 of (Ghosh 2005) and Table 3.10 of (IPCC, 2005).

also because many studies do not include all elements of the total projects costs, such as interest during construction, owners' costs, etc. (see section 4.2.4 and 7.1). The high costs for IGCC is partially a result of the advanced systems used in an IGCC and partly because the technology is not yet fully commercial, with high design and manufacturing costs. Various studies have predicted significant reductions in IGCC costs in the future. With tighter environmental controls and increasing desire for carbon capture, it is expected that IGCC plants will be installed in greater numbers worldwide. With more installations, the cost of IGCC plants is expected to decrease at a faster rate than the cost for PC plants. This is mainly because PC technology is fully mature, unlike IGCC, which has greater potential for cost reduction due to learning-by-doing.

Current IGCC systems have also been plagued by problems with reliability and availability. Operational difficulties are naturally greater when working with complex technologies. Although individual components of IGCC are all commercial, integrating them into one system, with all components working well simultaneously, has had its difficulties. There have been known problems associated with refractory linings, slow start-up and shut-down, hot gas cleanup, gas turbine operations, and operation of plants with a high-level of integration between its various components (Holt, 2004a). Thus, reaching 90% availability in current IGCC plants using single-train entrained-flow gasifiers is rather challenging – in fact, current demonstration plants have not yet achieved 85% availability on a yearly basis (Holt, 2004a). EPRI currently recommends the use of multiple gasifier-trains to increase reliability, but, unfortunately, this also increases cost significantly. Also, in order to increase availability, EPRI does not recommend the high degree of integration (particularly the ASU with the gas turbine), as has been done in European IGCC plants (Holt, 2004a).

Given that IGCC using entrained-flow gasifiers is considered as the 'mainstream' IGCC technology (as opposed to IGCC using fluidized-bed or moving-bed gasifiers),[344] most of current R&D effort is being invested in this particular technology. R&D efforts are focused on increasing reliability of the hot-gas-cleanup, improving the integration of various elements of an IGCC, developing advanced gas-turbines that can burn 'dirtier' or hydrogen-rich syngas, using novel thermodynamic cycles and fuel cells, etc. (Ghosh, 2005). In addition, development of advanced membrane-based air separation unit for producing oxygen will help reduce IGCC costs. Successful application of such R&D work is necessary for reducing cost and increasing reliability IGCC based on entrained-flow gasifiers.

6.4.1.1 Entrained-flow gasifiers in India

As mentioned earlier, most Indian coals are not amenable to entrained-flow gasification because of its high ash content and high ash-fusion temperature.[345] Despite this fact, many in the technology and policy community in India (and elsewhere) tend to rely on data for cost,

[344] Nearly 75% of the planned IGCC power plants are based on entrained-flow gasifiers (Texaco or Shell design) (PowerClean, 2004).

[345] Two coal-based entrained-flow gasifiers were setup by the Fertilizer Corporation of India in 1980 to produce ammonia and urea. The gasifiers were based on the Koppers-Totzek process (entrained-flow/slagging gasifiers) that required coal with low moisture and ash-content of about 20%. Not surprisingly, the gasifiers did not work with the high ash content (>35%) Indian coals and the plants were shut down "due to technological obsolesce and non-viability" (Department of Fertilizers, 2004). However, it might be possible to use coals from the north-east, which have low ash-content and lower ash-fusion temperatures, for IGCC systems.

efficiency, environmental and operational performance of coal-based IGCC technology using entrained gasifiers.[346]

Despite this limitation, IGCC power plants based on entrained-flow gasifiers may be useful in the Indian context for using oil-based feedstock, such as petcoke, heavy oils, refinery residue, specific coals from the northeast, etc. In fact, entrained-flow gasifiers are already in use in India to make fertilizers. For example, there are at least nine Shell gasifiers and two Texaco gasifiers that use fuel oil (low-sulfur heavy stock and naphtha) to make ammonia and urea (Higman and Sharma, 1998). Hence, the technology of gasifying hydrocarbon products is not new to India – there is more than 20 years of industrial experience. There is also considerable interest amongst the Indian oil industry in using the syngas produced using gasification of refinery products to generate electricity in an IGCC plant. Higman and Sharma (1998) have noted that adding a gasification train to an Indian refinery can provide many benefits including:

- freeing up of additional middle distillate that would otherwise be sent to the heavy-fuel oil pool,
- introduction of upgrading processes into the refinery flow scheme to produce a lighter product slate,
- greater flexibility in crude processing,
- providing a higher degree of desulphurization,
- lower solid waste production in comparison to combustion, and
- options for the refinery to produce multiple products such as hydrogen, methanol, carbon-dioxide – polygeneration

Many public and private oil companies, including ONGC, IOC, and Essar, are interested in using their refinery residues to generate power using IGCC; however, they are concerned about technology risks and the higher cost of IGCC plants. An advantage of using IGCC based on entrained-flow gasifiers is that Indian systems can benefit from the worldwide R&D investment in this technology.

6.4.2 Fluidized-bed gasification (FBG)

The fluidized-bed gasifier is a direct analog of the fluidized-bed combustion system – a bed of coal, ash, and adsorbents (such as limestone and dolomite for sulfur absorption) is maintained with upward-moving streams of steam and air/oxygen. Unlike combustion, the coal is only partially oxidized under pressure at temperatures less than 1000 ^{o}C. There can be multiple cyclone stages that recycle the fines elutriated with the syngas back to the bed. The temperature of the syngas at the exit can be between 700 to 1050 ^{o}C, and the process has moderate cold-gas efficiency. The fluidized-bed allows for greater fuel flexibility including the use of high-ash coals, biomass and waste, with one caveat that the feedstock in the bed must not stick to each other, i.e., it must have a high melting point (ash-fusion temperature) (DTI, 1998). These are fuels that cannot, in general, be used in entrained-flow gasifiers. On the other hand, FBG cannot be used for gasifying oil or other liquid fuels, and the lower gasification temperature limits the use of very low-reactivity feedstock such as pet-coke. The ash and the spent absorbents are generally removed as dry ash; although it is possible to soften and agglomerate the ash by

[346] In many cases, the specific gasifier to be used for an IGCC plant in India is unclear or unspecified, leading to further confusion about assumed efficiency, cost, and environmental performance.

operating the gasifier bottom hotter. The agglomeration allows for the ash to be less susceptible for leaching and reduces carbon content in the ash (Nexant, 2003).

FBG-based IGCC is expected to offer many of the environmental benefits discussed earlier. Fluidized-bed gasifiers tend to have high cold-gas efficiency, but the low carbon conversion might offset this advantage. However, similar to the entrained-flow gasifier-based IGCCs, FBG-based IGCC might also be expected to have high efficiencies in the future.[347] Unlike entrained-flow gasifiers that require a separate sulfur removal plant, sulfur is removed in a FBG using adsorbents in the bed; hence, production of large quantities of solid waste is an issue. In some cases, the solid waste from the gasifier has enough carbon that it can then be further combusted in a CFBC boiler (DTI, 1998).

FBG-based IGCC is not yet a commercial technology, although the atmospheric-pressure gasifier has been used in industry for some time. There are very few large-scale fluidized-bed gasifiers in operation worldwide, and they generally use air as oxidant rather than oxygen. Some of the main FBG processes include the high-temperature Winkler (HTW), British Coal Corporation gasifier,[348] U-GAS gasifier, Lurgi circulating fluidized-bed gasifier, Foster-Wheeler atmospheric and pressurized fluidized-bed gasifiers, Termiska Processer AB's TPS gasifier, KRW gasifier, and KBR Transport[349] gasifier. Many of these gasifiers are still in the development stage, and some are being evaluated for commercial operations. As with combustion, the fluidized-bed gasification can be done either under pressure (pressurized gasification) or with no pressure (atmospheric gasification). There are several small-scale atmospheric fluidized-bed gasification demonstration plants in Europe using biomass and waste as feedstock, and only a few plants have combined the gasification with electricity generation. The 6 MW_e IGCC demonstration plant in Varnamo, Sweden used a Foster-Wheeler pressurized fluidized-bed gasifer, but it is currently mothballed (Kwant and Knoef, 2004; PowerClean, 2004). The 80 MW_{th} Amercentrale plant in Netherlands uses a Lurgi CFB gasifer to gasify biomass and feeds the syngas into a PC boiler for electricity generation (Kwant and Knoef, 2004). The now –closed tri-generation Wujing Gas plant in China used eight U-GAS gasifiers in China to gasify coal to generate electricity, town gas, and chemicals. This plant is no longer in operation because the availability and efficiency of the plant did not meet the design criteria and because the economics and environmental concerns now favor the use of natural gas rather than coal-based syngas.[350] The 100 MW Piñon Pine IGCC demonstration plant using a KRW gasifier experienced many operational problems, and plant is currently for sale.[351]

[347] The projected improvements in IGCC efficiency by IPCC (2005) and CETC (2005) are mainly based on information from entrained-flow gasifiers, although it may also be applicable to IGCCs based on other types of gasifiers.
[348] This gasifier is now marketed by Mitsui Babcock Energy Ltd. (MBEL).
[349] The transport gasifier lies in between a fluidized-bed and entrained-flow gasifier, as it uses pulverized coal. The technology is still in the developmental stage. See (NETL, 2005).
[350] Guodong Sun – personal communication (March 2006).
[351] The KRW gasifier had 18 separate startups, each ending with a malfunction. Despite various attempts to fix it, the gasifier continuously operated for a maximum of only 25 hours continuously with a cumulative total of 127 hours. Although the use of KRW gasifiers may be technical feasible, it might not be suggested for utility use. See: Piñon Pine IGCC – Project Fact Sheet: http://www.netl.doe.gov/cctc/summaries/pinon/documents/pinon.pdf.

Despite the poor operational record of existing FBG-based IGCC systems using coal (for example, Wujing and Piñon Pine), it is expected that IGCC using fluidized-bed gasifiers would perform comparably to IGCCs based on entrained-flow gasifiers; particularly with improvements to the fluidized-bed gasifiers combined with the balance-of-system experience gained from operation of IGCCs based on entrained-flow gasifiers. Given the relatively little commercial experience, it is difficult to properly assess the efficiency and cost of FBG-based IGCCs. A theoretical NETL study using KRW gasifiers indicated efficiencies of 44-48% (HHV) with plant cost about $1100/kW[352] (NETL, 2000a).

6.4.2.1 Fluidized-bed gasification in India

The properties of Indian coal makes it better suited for fluidized-bed or moving-bed gasification. Hence, there has been considerable R&D on developing a fluidized-bed gasification process using Indian coals, primarily led by the Indian Institute of Chemical Technology (IICT) and BHEL. There are, however, no commercial-scale fluidized-bed gasifiers using Indian coal in operation.

In the 1960s, three Winkler gasifiers were used at Neyveli to generate syngas for fertilizer production using lignite as feedstock. These gasifiers were shut down in 1979 because of high costs that resulted from operational problems associated with caking and slag formation – a result of having marcasite in the lignite, which reduces the ash-fusion temperature, leading to slagging (Nexant, 2003). IICT in Hyderabad had installed and operated a small 4 ton-per-day (tpd) fluidized-bed gasifier for developing gasification processes for replacing the use of fuel oil in small industries (CMPDIL, 2004).

In the early 1990s, BHEL's R&D focused on developing pressurized fluidized-bed gasification (PFBG) process for Indian coals. By 1993, an 18 tpd gasifier was developed by BHEL Corporate R&D in Hyderabad to gasify Indian coal at pressures of about 11 atmospheres and temperatures around 1000^{o}C (Thirumalai, 2003). Information from this process and equipment development unit was then used to develop a 150-tpd, 6.2 MW$_e$ pilot scale PFBG-based air-blown IGCC in Tiruchirapalli (Trichy) in 1997. The pilot plant was supported by a USAID grant to provide modeling and process design support.[353] The gas from the 150-tpd gasifier passed through three refractory lined cyclones, before being cleaned by a wet-scrubbing system and burned in a combined cycle power unit. The gas parameters were similar to the laboratory-scale plant with a calorific value of about 1000 kcal/m^3 (Thirumalai, 2003). The pilot plant was operated for about 50 hours in IGCC mode in 1998 (Nexant, 2003). Although the pilot plant worked fairly well in a number of trial operations, there were some operational problems including clinker formation, failure of refractory linings, failure of bottom-ash cooler tubes, gaskets, seals, etc. Nonetheless, BHEL has apparently gained enough learning from this pilot plant that it is planning to build a 100-MW IGCC plant using its PFBG technology with the support of NTPC.

According to BHEL analysis, it is expected that the 100-MW demonstration plant using its PFBG technology could have efficiencies between 33-40%, with a total plant cost of about Rs.

---

[352] In 1st Quarter 1999 dollars. See: http://www.netl.doe.gov/technologies/coalpower/gasification/system/krw3x_20.pdf

[353] Personal communication – Scott Smouse (2005).

600 Crores, with a third of the cost allocated for the gasification island (Thirumalai, 2003). Most of the technologies required for the demonstration plant are available with BHEL;[354] technologies for gas cleaning, pumps, high temperature and pressure valves, and high capacity compressors will have to be sourced from elsewhere (Gopinath et al., 2002). However, such a demonstration plant will have a very high cost of more than Rs. 6 Crore/MW (compared to the Rs. 3-4 Crore/MW for a PC plant). Similarly, Nexant (2003) analysis for an 800 MW_{net} IGCC demonstration plant using U-GAS technology[355] also indicate a total plant cost of about Rs. 6 Crores/MW[356] with efficiency of about 40% (HHV). In addition, compared to a supercritical PC plant, an IGCC based on U-GAS fluidized bed gasifiers would have 30 times lower particulate emissions, 7 times lower NOx emissions, 20% lower SOx emissions, and 2.5 times lower water discharge (Nexant, 2003). The IGCC is expected to consume at least 1.5 times less water per MWh than standard PC plants, which can be significant advantage, as demand for water rises in India.

6.4.3 Moving-bed gasification

The moving-bed gasifer is the analogue of the stoker-grater combustion system. The oxidant (steam and air/oxygen) is blown into the bottom of the gasifier, and the generated syngas flows upward through the feedstock; the feedstock itself is moving downwards as the bottom of the bed is gasified. Unlike fluidized-bed systems, the gas is cooled as it moves upward by the incoming feed and becomes tarry as the feed devolatilizes. Cleaning up of this tar-filled gas is one of the key technical and environmental issues in a moving-bed gasification process (DTI, 1998).[357] Unlike entrained-flow or fluidized-bed gasifiers, there are separate zones of coal processing within the gasifier (Bonk, 2005). The spent ash is removed at the bottom of the gasifier either as dry-ash or as slag. To prevent caking of the feedstock there are moving grates to break up coal chunks, and the use of coal fines is limited (Nexant, 2003). Fuel flexibility of moving-bed gasifiers is similar to that of fluidized-bed gasifiers.

There are two main commercial moving-bed gasification processes: the Lurgi dry ash gasifier and the British Gas Lurgi (BGL) slagging gasifier.[358] The Lurgi dry ash gasification process (now owned by Sasol-Lurgi) is a very mature commercial technology that has been extensively used worldwide to produce town gas and fuel for chemicals production, particularly F-T liquid fuels.[359] This process uses a high steam-oxygen/air ratio to keep the gasifier temperature relatively low to prevent ash fusion. The low temperature implies that the process is more suitable for highly-reactive coals such as sub-bituminous coals and lignite. The syngas exits the gasifier with temperatures around 300-500^{o}C, and the tar and oils in the gas are removed using a water-quench system. Lurgi gasifiers have been operated in Sasol, South Africa using coals with high ash-content and ash-fusion characteristics, and hence they might be suitable for typical

---

[354] These technologies include: main gasifier, cyclone separators, coolers, heat exchangers, coal feeders, steam turbine and auxiliaries (Gopinath et al., 2002)
[355] The Nexant process model includes eight U-GAS gasifiers and two F-class gas turbine trains to produce about 870 MW gross (800 MW net).
[356] These costs do not include IDC. Cost with IDC would be Rs. 8 Crores/MW. (Costs with mid-2002 pricing) (Nexant, 2003).
[357] This tar removal issue is also present in biomass-based gasifiers.
[358] Both gasifiers use oxygen as an oxidant, rather than air.
[359] The Lurgi technology has been used in South Africa for over 50 years, and it has also been used in Germany, China, and the United States.

Indian coals. The BGL gasifier, developed in the 1970s, is similar to the Lurgi dry ash gasifier, except that the ash is removed as slag from the gasifier.[360] The syngas is slightly hotter than Lurgi gasifier (450-500 ^{o}C), with a water-quench system for removing tars and cooling the gas. The removed tars and oils are then recycled back to the gasifier. The BGL gasifier is not particularly suitable for Indian coals, because of their high ash content and high ash-fusion temperatures.

The reliability and availability of the Lurgi and BGL gasifiers are very high (>90%). However, the price and efficiency of IGCC systems based on moving-bed gasifiers are not readily available, because these gasifiers have been used for chemical productions and not been demonstrated for use in an IGCC. Nonetheless, a theoretical NETL study using BGL gasifier for a 400 MW IGCC using a quench-based cold gas cleanup system claimed efficiencies and plant cost of 45% (HHV) and $1150-1200/kW,[361] respectively (NETL, 2000b).

6.4.3.1 Moving-bed gasification in India

Moving-bed gasification might indeed be an important technology for IGCC development in India, although the problems associated with cleaning of tars in the syngas has favored R&D investment towards fluidized-bed gasifiers.

BHEL and IICT are the key organizations involved in moving-bed gasification R&D in India. IICT at Hyderabad setup a 24 tpd Lurgi moving-bed gasifier to test the feasibility of Indian coals for IGCC in the 1980s; this gasifier remains in operation (Nexant, 2003). Prior to building their fluidized-bed gasifer, BHEL set up a 6.2 MWe IGCC using a 150 tpd moving-bed gasifier in 1989 in Trichy. The IGCC worked fairly well and delivered more than half a million units of electricity to the Tamil Nadu grid (Gopinath et al., 2002; Thirumalai, 2003). The gasifier used sub-bituminous coals sized between 6 to 25 mm, and operated at pressures of 10 atmospheres and a maximum temperature of 1100^{o}C (Thirumalai, 2003). The gas exited the gasifier at about 540^{o}C, and it was cooled and cleaned in a wet gas cleaning system. However, lack of appropriate technology for removal of tar and oils from the syngas was a disadvantage. Furthermore, the limited use of fines, the requirement of proper coal sizing, and the inability to further scale up the gasifiers pushed BHEL into abandoning this technology in favor of fluidized-bed gasifiers (Thirumalai, 2003).

6.4.4 Polygeneration

Gasification, unlike combustion, is amenable to generating multiple products. The syngas produced by gasifying coal or other feedstock can directly substitute natural gas. Thus, it can be used for producing electricity in an IGCC power plant, making ammonia, hydrogen and methanol for fertilizer production, making F-T liquid transportation fuels, and be used as fuel for residential and commercial heating. In fact, a syngas stream can be used to generate multiple products – an approach referred to as "polygeneration." A key advantage of polygeneration is the potential economic and/ energy security benefits that accrue from products such as F-T fuels.

[360] The BGL technology has been successfully commercialized at the 75 MW Schwarze Pumpe power plant, Germany.
[361] 1st Quarter 1999 dollars.

Hence, gasifiers might not be used only in IGCCs in the future, but rather in a chemical plants that might also be generating electricity for the plant's own use and for the grid.

In the United States, many NGCC power plants have shutdown because of high natural gas prices and the use of natural gas in industrial applications is being reduced. In this context, a National Gasification Strategy using domestic coal reserves the generation of natural gas and other products has been proposed to alleviate pressure on natural gas markets and to enhance energy security (Rosenberg et al., 2005). Similarly, in China, gasification of coal is being considered mainly for polygeneration or exclusive chemical production – much of it promoted by the Chinese coal industry. Current economics of the power sector in China do not allow gasification projects exclusively intended for electricity generation (using IGCC) to be competitive with combustion technology.[362] Thus, for electricity generation, China has been focusing on advanced combustion technologies such as ultra-supercritical PC and advanced CFB, while gasification is being considered for chemical production and polygeneration.

6.4.5 Underground gasification and IGCC

Underground coal gasification (UCG) is receiving increasing attention as a way to utilize unmineable coal seams. The key technology process involves drilling injection and production wells into coal seams, and injecting an oxidant (oxygen or air) and steam, if necessary, into the coal to produce a low-temperature, high-pressure syngas.[363] The transport of gases from the injection and outlet boreholes controls the reactions, with UCG development mainly focused on enhancing the connections between the boreholes, controlling gasification processes, and scaling up of operations (DTI, 2004b). The gas composition of UCG-syngas is very similar in calorific value to that produced in surface gasifiers, but with higher methane content (DTI, 2004b).

Although process controllability and consistency of product from UCG are big concerns, there are several advantages (DTI, 2004b; Friedmann, 2005):

- The use of unmined and unmineable coal deposits with obstacles to mining such as high fault frequency, volcanic intrusions and other complex depositional and tectonic features;
- No large-scale environmental impact, especially when compared with impacts of coal mining.[364] There are, however, the problems of subsidence (as with underground coal mining) and possible alterations of underground hydrology, especially for UCG at shallow depths.
- No need for ash or slag removal and handling, since inert material mostly remains underground;
- No production of SO_x, since most of the sulfur in coal is converted to H_2S, which can removed using standard techniques;
- Little or no production of NO_x (especially if oxygen is used as oxidant rather than air) because of low gasification temperatures and low quantities of organic nitrogen in coal;

[362] Personal Communication – Guodong Sun (2005).
[363] At the well-head, the temperature and pressure of the UCG-syngas produced using oxygen could be as high as 200 ^{o}C and 100 bar (DTI, 2004b).
[364] There have been some concerns about contamination of ground water, although this has not been substantiated by U.S. studies and the Australian program, which were specifically monitored for this issue (DTI, 2004b; Friedmann, 2005).

- Reduced capital expense in comparison to surface gasifiers, since there is no need to purchase gasifiers or build ash/slag handling facilities
- Increased energy security as locally produced UCG-syngas can be a direct substitute for natural gas (similar to polygeneration aspects discussed above).

UCG has been demonstrated at commercial-scale in the former Soviet Union,[365] and R&D on UCG has been conducted in the United States since the mid-1940s (although it was more active in the 1970s, following the energy crises). There were 33 field trials conducted by DOE before the program wrapped up by the early 1990s (Friedmann, 2005). In Europe, UCG trials were conducted in 1990s in Spain, followed by an initiative to study feasibility of UCG in the United Kingdom. China has also been actively involved with UCG since 1986 for utilizing residual coal pillars and shallow coal seams with man-built galleries in the coal seam being used as gasification channels (DTI, 2004a). The Australian UCG project in Chinchilla, Queensland, based on Ergo Exergy technology is, perhaps, the closest to full commercialization; the technology is based on Soviet technology and expertise (DTI, 2004b).[366]

The syngas produced by UCG can be used for any number of applications, including chemical production, F-T liquid fuels production, and direct power generation (as a substitute for natural gas or co-firing in a traditional boiler with coal or other fuels). The UCG process can also be integrated with combined cycle power generation (UCG-CC), similar to standard surface-IGCC discussed above. For oxygen-based UCG, the gas turbine can be used to power the ASU and the compressor for the oxidant (air or oxygen) before it is injected underground.[367] Furthermore, the UCG-syngas at well-head has high pressure and velocities, which can be directly used by turbine expansion for power generation – power than can be used for internal consumption by the ASU (DTI, 2004b).

In the Indian context, there is significant interest in using UCG to extract energy from inaccessible, deep coal seams (Planning Commission, 2006). The use of UCG on the high ash Indian coals would significantly reduce environmental impacts of coal mining and ash handling/storage. Furthermore, the commercial use of deeper coal seams would significantly increase the amount of coal usable for energy purposes in the country, although better assessment of deeper coal resources is necessary before undertaking UCG activities (see section 4.1.1).[368] As of now, both GAIL and ONGC are interested in pursuing UCG testing in the country. GAIL has recently linked up with Ergo Exergy Technologies to undertake pre-feasibility studies for a 5 MW pilot-scale UCG (which can be later scaled up to 750 MW) in the deep lignite mines at Barmer, Rajasthan.[369] In 2004 ONGC linked up with a Russian institute,

---

[365] See: http://www.ergoexergy.com/eUCG_his.htm. One plant in Uzbekistan has produced UCG-syngas for over 46 years (Friedmann, 2005).
[366] See: http://www.ergoexergy.com/about_us_ourb_projects.htm#
[367] See: http://www.ergoexergy.com/eUCG_pow.htm#
[368] Geological structures will have to be identified at the coal seam depth with a resolution of at least the coal seam thickness, and over an area of coal large enough to meet UCG project objectives. Hence, detailed exploration is necessary using closely-spaced boreholes, three-dimensional seismic surveys, and data-analysis software packages (DTI, 2004b).
[369] See: "Underground coal/lignite gasification tech — GAIL gets board nod to get license from Canadian firm," Richa Mishra, Hindu Business Line, Feb 18, 2006. http://www.thehindubusinessline.com/2006/02/18/stories/2006021803170200.htm

Skochinsky Institute of Mining, to conduct feasibility studies, followed by pilot plants, in deep lignite and coal seams in Rajasthan, Tamil Nadu, and Gujarat. During its oil and gas explorations, ONGC seems to have discovered about 120 BT of coal seams deeper than 600 m in Gujarat alone; conversion of even half of this coal resource could result in 15 trillion cubic meters of gas (PIB, 2004). Private oil and gas companies, such as Reliance, are also interested in developing UGC.[370]

While there is great interest in promoting UCG in India, no UCG project is operational at this point. Thus, the results from the first few pilot plants are crucial for assessing the feasibility of large-scale use of UCG technology for Indian coals.

[370] See: "Reliance plans underground coal gasification projects," Ambarish Mukherjee, Hindu Business Line, December 7, 2005. http://www.thehindubusinessline.com/2005/12/07/stories/2005120704210100.htm

6.5 Add-on pollution control technologies

Cleanup Technology	**Category**	**Emission cleaned**	**Applicable technologies**
Coal washing/beneficiation	Pre-combustion	fly ash sulfur mercury carbon-dioxide[371]	PC, IGCC
Electrostatic precipitator (ESP)	Post-combustion	fly ash	PC, FBC, IGCC
Bag filter	Post-combustion	fly ash	PC, FBC
Cyclone	Post-combustion	fly-ash mercury	FBC, IGCC
Sulfur removal plant	Pre-combustion	sulfur	IGCC
Limestone	In-combustion	sulfur	FBC
Flue gas desulfurization (FGD)	Post-combustion	sulfur	PC
Low-NO_x burners	In-combustion	nitrogen oxides	PC
Selective Catalytic Reducers	Post-combustion	nitrogen oxides	PC
CO_2 shift reactor	Pre-combustion	carbon-dioxide	IGCC
Amine scrubbing	Post-combustion	carbon-dioxide	PC, IGCC, FBC

Table 31: Pollution reduction technologies

As discussed earlier in section 3.3.3, stack flue gases from boilers consists mainly of particulates, sulfur oxides, nitrous oxides, heavy metals, and carbon-dioxide – chemicals that cause serious health and environmental damages. While there are a range of technologies for reducing the emissions of these pollutants, they are typically included as part of specific coal-utilization technology packages. Nonetheless, in the Indian context, it is important to discuss pollution control technologies separately because only one pollution-reduction technology (the electrostatic precipitator) is in widespread use in India.

There are three broad categories of add-on pollution-reducing technologies: pre-combustion, in-combustion and post-combustion (see Table 31). Coal washing and beneficiation can be considered as pre-combustion emission cleanup technology since it increases plant efficiency, reducing the overall amount of all pollutants, and, particularly, fly ash. Low NO_x burners in PC boilers and gas turbines, and the use of limestone for sulfur removal in fluidized-bed combustion and gasification can be viewed as 'in-combustion' pollution control technologies. Cleanup technologies for PC plants, such as electrostatic precipitators, flue-gas-desulfurizers, and selective catalytic reducers, are considered as post-combustion technologies (discussed in section 6.1). These post-combustion technologies are also considered as 'add-ons', and they are only added onto power plants if environmental regulations are effectively enforced. Aspects of these technologies in the Indian context were discussed earlier. In contrast, the cleanup technologies in an IGCC plant to remove particulates and sulfur from the syngas are viewed as pre-

[371] Although carbon content in coal is not reduced by coal washing, CO_2 is reduced because of increase in cycle efficiency.

combustion technologies, because gas cleanup prior to combustion is necessary, lest the gas turbine be damaged. Carbon capture technologies can be either post-combustion (for example, amine scrubbers in a PC plant) or pre-combustion (for example, CO_2 shift reactors in an IGCC).

Except for carbon capture and storage, we do not explore broader emission control technologies in detail in this paper (even though issues such as mercury and PM2.5 control obviously are important). It is, however, clear that all cleanup technologies are constantly improving, similar to the core power-generation technologies themselves. In the Indian context, as long as environmental protection remains a high priority for decision makers, environmental controls for power plants will continue to be tightened and enforced over time and better control technologies will be routinely deployed.

6.6 Carbon Capture and Storage[372]

Control of carbon-dioxide emissions from power plants is becoming an important issue for reducing global carbon-dioxide levels in the atmosphere (see section 3.4). Reducing atmospheric CO_2 levels requires sustained global effort on various fronts:

1) reducing energy demand through conservation, redesigned buildings, and lifestyle changes (particularly in urban areas),
2) increasing efficiency of energy conversion and end-use processes,
3) increasing the use of low and near-zero carbon energy sources (renewable, nuclear, etc.),
4) switching to less carbon-intensive fuels (natural gas, coal-biomass, etc.),
5) sequestering CO_2 by enhancing the natural sinks such as forests, etc., and
6) capturing and storing CO_2 from emission sources.

For specifically reducing CO_2 emissions from coal-power plants, only the second, fourth, and sixth options are possible. First, with increased efficiency of power plants, coal use and carbon emissions per unit of electricity generated can be reduced. Thus, installing high efficiency power plants is an important first step in reducing CO_2 emissions. Second, switching from coal to coal-biomass mixtures can help reduce the carbon intensity of coal-based power generation. Finally, the CO_2 generated from power plants can be captured and stored. In this section, this latter possibility is discussed with a brief description of several different capture technologies for power plants and different kinds of storage possibilities.

We first note that carbon capture and storage (CCS) remains highly expensive and there are concerns among the general public about its long-term safety and environmental impacts. There is no doubt that CCS options will have to be first explored in industrialized countries before they are deployed in developing countries, like India. A number of industrialized countries, particularly Australia, U.S. and the European Union are already exploring various facets of CCS. Although India has no GHG commitments at present and has low GHG emission levels, we believe that it is in India's interest to assess possible use of CCS in the Indian power sector. Although the technology may or may not be used in the near future, assessing CCS potential in India is useful for long-term strategic technology planning, since the magnitude and distribution of CCS options will have implications for future coal-based power.

It is also important to realize that exploring capture of CO_2 in power plants is meaningless unless realistic options for storing the captured CO_2 are also realized at the same time. While technologies for capture can be imported or transferred, geologies cannot be. Hence, a well-established potential and ability to store CO_2 in local geologies is a prerequisite for thinking about making any serious investments in capture technologies in power plants.

The current status and emerging new technologies for capturing and storing carbon-dioxide has been reviewed in the recently released IPCC Special Report on Carbon Dioxide Capture and Storage (IPCC, 2005). We first summarize the basics of the capture and storage technologies from the IPCC report, and then we discuss the current status of, and future possibilities of, carbon capture and storage in India. Transport of CO_2 is another important intermediate issue

[372] We specially highlight carbon capture and storage in this paper because of its growing interest in the Indian context.

between capture and storage, but it is not discussed here—see IPCC (2005) for more details on transport issues.

6.6.1 Capture technologies

Capture of carbon dioxide from flue gases (or other gas streams) is not new. It has been used in industrial processes for 80 years, although most of the captured CO_2 is vented to the atmosphere. Currently, CO_2 capture technologies are used for natural gas purification, production of hydrogen-rich syngas for manufacture of ammonia and methanol, and carbonation of beverages and other food processing.

With regard to power generation, there are three major systems that are amenable to carbon capture: post-combustion (PC, FBC), oxy-fuel combustion (PC, FBC), and pre-combustion (APFBC, IGCC). In a post-combustion system, clean flue gas[373] at atmospheric pressure with CO_2 concentrations less than 15%[374] is passed through equipment that selectively separates much of the carbon dioxide, which is then stored away for storage. The remaining flue gas is then vented to the atmosphere. In a pre-combustion system, the produced syngas in an IGCC (or the fuel gas in an APFBC) will be sent to a CO_2 shift reactor, where the carbon monoxide in the syngas will be converted to carbon dioxide and hydrogen using a water gas shift reaction.[375] The resulting gas CO_2/H_2 mixture, with CO_2 concentrations in the range of 15-60% (dry basis), can then be separated using physical or chemical solvents. Prior to the water shift reactor, other impurities, such as particulates and H_2S, need to be removed from the syngas (using ESP and a Claus unit, for example). For oxy-fuel combustion capture, the flue gas, which is mainly CO_2 and H_2O after particulate and sulfur cleaning, can be cooled and dried to have CO_2 concentrations between 80 to 98%. This gas can then be compressed, dried, and either sent directly for storage or further purified before storage (IPCC, 2005).[376]

The main categories of capture technologies are described below (IPCC, 2005):

- Chemical solvents: Gas containing carbon-dioxide is cooled to 40-60^{o}C and forced through an aqueous alkaline solvent such as amine (MEA or MDEA[377]). The CO_2 in the gas chemically reacts with the solvent and binds to it. The flue gas is washed and sent out of the system with 80-95% of CO_2 removed. The CO_2-rich solvent is sent to a 'regeneration vessel', where the CO_2 is desorbed from the solvent because of elevated temperature (100-140^{o}C) and pressure. The regenerated solvent is then re-circulated back for capture. Regeneration of the solvent requires thermal energy input to maintain the high temperature, leading to an energy penalty.[378] Furthermore, nearly 1.5 ton of low-pressure (50 psig) steam needs to be extracted per ton CO_2 for the capture process, which

[373] The flue gas from the boiler need to be first cleaned of particulates, SO_x and NO_x using ESP, FGD, and SCR, respectively, before it enters the CO_2 removal stage.
[374] For natural gas based plants, flue gas CO2 concentrations can be between 7-10%, and for coal-fired boilers, 12-14% (IPCC, 2005).
[375] $CO + H_2O \rightarrow CO_2 + H_2$
[376] Removal of impurities in a high CO_2 concentration flue gas from oxy-combustion or IGCC systems might be required to prevent corrosion in transport pipelines or if legislation deems the impure liquid as hazardous; in addition, removal of inert gases to low concentration may be necessary to prevent two-phase flow conditions in the pipeline (IPCC, 2005).
[377] MEA – Monoethanolamine; MDEA – Methyldiethylamine
[378] The energy penalty is in addition to the power needed for operating pumps and fans.

can reduce the overall power generation (Simbeck, 2004). For post-combustion use, it is important to remove SO_x and NO_x from the flue gas to very low levels before attempting carbon capture, since these impurities bond to the solvents irreversibly, reducing its absorptive property for CO_2 and increasing the risk of solid formations in the amine solution. It also results in excess consumption of chemicals to regenerate the solvent and produces high waste streams (IPCC, 2005).[379]

- Physical solvents: Physical solvents, such as Rectisol and Selexol, rely not on a chemical reaction but on physical absorption of CO_2 to the pressurized solvent. The absorbed gas is removed from the solvent when pressure is released.[380] Physical solvents are applicable for gas streams with high CO_2 concentration – i.e., for IGCC or oxyfuel systems.

- Pressure swing adsorption:[381] Unlike absorption processes, adsorption processes are less selective and they are generally used for purifying syngas or for H_2 separation. Adsorptive materials, such as molecular sieves (such as zeolites) or activated carbon, are pressurized and depressurized in a cyclical manner. Certain kinds of gases are adsorbed to the material under high pressure; these adsorbed gases are then released under low pressure.

- Membranes: Specially manufactured membranes can allow selected gases to permeate through them, driven by a pressure difference across the membrane. The nature of the material determines the gas selectivity, with polymeric membranes being more common.[382] Currently, polymeric membranes are used for separating CO_2 from natural gas in industrial processes. Membranes also have a higher energy penalty when compared to standard absorption processes, with a lower percentage of CO_2 removed. However, a hybrid membrane-absorbent system is now being considered for flue gas recovery. Such a hybrid system increases contact surface area between the flue gas and absorbents, resulting in a more compact system and less operational problems associated with conventional absorbent systems. Another future option is the ‘facilitated membrane’, where embedded chemicals in the membrane can facilitate the transport of gases through the membrane.

- Solid sorbents: Solid sorbents, such as sodium, calcium, and potassium oxides, carbonates (limestone/dolomite), and lithium-based sorbents, can be used cyclically as wet absorption systems to selectively remove CO_2 from flue gas streams. The gas-rich solids can then be either moved into a different reactor for regeneration, or switched between absorption and regeneration modes in a batch-wise manner. A significant advantage of solid sorbents is that they can be operated at a wide range of high temperatures (with maximum temperatures greater than $600^{o}C$), thereby reducing the

[379] See section 3.3.2.2 of IPCC (2005) for a discussion of post-combustion flue-gas pretreatment required for an economical use of chemical solvents.
[380] Energy consumption is rather low since only the energy for pressurized the solvent is required.
[381] It is also possible to operate an adsorption process using temperature swing adsorption, although it is not common (IPCC, 2005).
[382] Other membrane materials include metals, ceramic, and carbon contactors (IPCC, 2005).

energy penalty paid by conventional solvent systems for lowering the flue gas temperatures. However, solid sorbents need further development to reduce their cost, increase their absorption capacity, and increase chemical and mechanical stability for long periods of cycling.

- Cryogenic liquefaction/distillation: Similar to standard cryogenic oxygen production, gas streams with relatively high initial CO_2 concentration (80-95%) can be purified further (up to 99.9% CO_2 purity) by liquefying the gas and distilling it in columns. This method could be applicable to oxy-fuel combustion flue gas streams, for syngas that has already been water-gas shifted, and for further purifying CO_2 steams from post-combustion capture. Ultra-pure CO_2 streams may be necessary to avoid two-phase flow conditions during pipeline transport.

A summary of the above carbon capture technologies divided into current and emerging technologies is shown below in Table 32.

	Post-Combustion Capture		Oxyfuel Combustion Capture		Pre-Combustion Capture	
Applicable Power technologies	PC, CFBC, PFBC		Oxyfuel-PC/FBC		IGCC, APFBC	
Separation Task	CO_2/N_2		O_2/N_2; CO_2/impurities		O_2/N_2; CO_2/H_2	
Capture Technologies	Current	Emerging	Current	Emerging	Current	Emerging
Solvents (absorption)	Chemical Solvents	Improved solvents; novel contacting equipment; Improved process design			Chemical solvents; Physical solvents	Improved solvents; novel contacting equipment; Improved process design
Membranes	Polymeric	Ceramic; Facilitated transport; carbon contactors	Polymeric	Ion-transport membrane (ceramics); Facilitated transport	Polymeric	Ion transport membranes; Ceramic; Palladium; Various contactors
Solid Sorbents	Zeolites; Activated carbon	carbonates; metal oxides	Zeolites; Activated carbon	Adsorbents for O_2/N_2; oxygen chemical looping	Zeolites; Activated carbon	Adsorbents for O_2/N_2; oxygen chemical looping; Carbonates; metal oxides; silicates
Cryogenic	Liquefaction/ Distillation	Improved distillation; Hybrid processes	Liquefaction/ Distillation	Improved distillation; Hybrid processes	Liquefaction / Distillation	Improved distillation; Hybrid processes

Table 32: Carbon Capture Technologies. Source: Adapted from IPCC 2005.

Box 4: Cost measures for CO_2 capture

Different cost measures for assessing CO_2 capture costs can provide different perspectives and sometimes it might even color the choice of technology and strategies to pursue. Given its importance, some of the more common cost metrics are discussed briefly (IPCC, 2005):

- Capital cost: Capital cost for CO_2 capture technology represents the total cost to design, purchase, and install a capture system, either in a new power plant or in an existing power plant. It may include the cost of various other plant components, as well as purification and compression systems. Given that CO_2 capture is not yet mandated, it is also reasonable to compare the incremental capital cost – i.e., the difference between capital cost with and without carbon capture, for a power plant using specified power and capture technologies.

- Incremental cost of electricity (COE): The impact of carbon capture on the cost of the final product (electricity) is an important metric of the economic impact of carbon capture. The incremental COE is the difference between the levelized COE with and without carbon capture. However, calculation of COE varies enormously among different studies because of varied underlying assumptions, such as fuel cost, total capital cost requirement, fixed charge factor, operating costs, plant efficiency, capacity factor, discount rate, plant lifetime, etc.

- Cost of CO_2 avoided: The cost of avoided CO_2 is the average cost of reducing the emission of a ton of CO_2 in a capture plant while providing the same amount of electricity as a reference plant without carbon capture. This metric allows for the inclusion of additional emissions from a capture plant that result from operating the capture equipment. Although widely used, this metric can be misleading because the metric can be heavily influenced by the choice of reference plant. It is best to compare the avoided cost of a capture plant using a similar-sized reference plant with the same underlying technology (e.g., supercritical PC with capture vs. supercritical PC w/o capture). However, many studies 'fix' the reference plant (subcritical PC) and calculate the avoided cost using capture plants with a different types of technologies (ultra supercritical PC, high efficiency IGCC, etc.) – leading to some confusion.

- Cost of CO_2 captured: Rather than measuring the cost of CO_2 avoided, the cost of CO_2 captured is average cost of capturing CO_2 from a given power plant. In essence, this metric reflects the economic viability of a capture system under various market prices for CO_2. However, unlike the cost of CO_2 avoided, the cost of CO_2 captured does not account for the increased energy consumption in a capture plant.

6.6.1.1 Performance and cost of carbon capture in power plants

The performance and cost of carbon capture is an important element for deciding the choice of base technology for new green-field projects, and for deciding if (or when) to install capture technologies as retrofits to existing power plants. Estimated performance and costs of carbon capture vary widely in literature, primarily because of different assumptions regarding technical and financial factors chosen by any particular study. Technical factors such as plant size, net efficiency, fuel properties, load factors, etc., can affect capital cost, and financial factors such as fuel cost, cost of labor and construction, interest rates, debt-to-equity ratio, discount rates, etc., can affect the cost-of-electricity (see section 7.1 for more detailed discussion). Specifically for carbon capture, there are several sources of differences and variabilities (IPCC, 2005):

- the choice of capture technology,
- the choice of base power generating technology,
- whether the capture technology is a retrofit or a green-field project,
- whether the costs include costs of CO_2 compression and transportation (pipelines, etc.),
- timeframe and assumed maturity level of technologies (first of a kind or n^{th} plant), and
- use of different metrics for assessing capture costs – capital cost, cost of avoided CO_2, cost of CO_2 captured, cost of electricity, etc.

The current best understanding of the performance and cost of carbon capture has been well summarized by the IPCC Special Report (see Table 33). The information in the IPCC (2005) report is based on studies and cost estimates made for power plants that are planned to be built in Europe and United States. There are no similar studies for installing capture power plants in developing countries such as China and India, and hence information in Table 33 must be understood as only a guide for developing countries and detailed project-based engineering studies need to undertaken in developing country contexts. In any case, the decision to capture CO_2 in a power plant will be based on specific local economic and environmental factors that relate to the plant.

Performance and Cost Measures	New PC Plant			New IGCC Plant			New NGCC Plant		
	Range			Range			Range		
	low		high	low		high	low		high
Emission rate without capture (kgCO_2/MWh)	736	-	811	682	-	846	344	-	379
Emission rate with capture (kgCO_2/MWh)	92	-	145	65	-	152	40	-	66
Percent CO_2 reduction per kWh (%)	81	-	88	81	-	91	83	-	88
Capture energy requirement (% more input / MWh)	24	-	40	14	-	25	11	-	22
Plant efficiency without capture, HHV basis (%)	39	-	43	37	-	45	50	-	52
Plant efficiency with capture, HHV basis (%)	29	-	34	30	-	38	42	-	45
Total capital requirement without capture (US$/kW)	1161	-	1486	1169	-	1565	515	-	724
Total capital requirement with capture (US$ /kW)	1894	-	2578	1414	-	2270	909	-	1261
Percent increase in capital cost without capture	44	-	74	19	-	66	64	-	100
COE without capture (US$/MWh)	43	-	52	41	-	61	31	-	50
COE with capture only (US$/MWh)	62	-	86	54	-	79	43	-	72
Increase in COE (US$ / MWh)	18	-	34	9	-	22	12	-	24
Percent increase in COE	42	-	66	20	-	55	37	-	69
Cost of CO_2 captured (US$/t$CO_2$)	23	-	35	11	-	32	33	-	57
Cost of CO_2 avoided (US$/t$CO_2$)	29	-	51	13	-	37	37	-	74

Table 33: Performance and cost of carbon capture in new power plants: All costs are for capture only, and do not include transport and storage costs. PC plants use supercritical steam conditions. LHV efficiency was converted to HHV using LHV/HHV = 0.96 and 0.9 for coal and natural gas, respectively. Costs are in 2002 pricing, assuming bituminous coal price of US$1.0--1.5/GJ and natural gas price of US$2.8--4.4/GJ (on LHV basis). Power plant sizes vary from 400 – 800 MW without capture and 300—700 MW with capture. Capacity factors vary from 65-85% for coal and 50-95% for natural gas plants. Source: Adapted from (IPCC, 2005).

As Table 33 indicates, the cost of capturing CO_2 from new PC power plants using post combustion capture is generally more expensive and requires greater energy input than that of pre-combustion capture in IGCC plants. The plant efficiency drops nearly 10 percentage points for PC plants with and without capture, compared to about 7 percentage points for IGCC. The increase in capital cost for PC plants with capture compared to PC plants without capture ranges between 44-74% in different studies, and the same for IGCC is about 19-66%. Similarly, the increase in cost of electricity in PC plants ranges between 42-66% in different studies, whereas for IGCC it is 20-55%; the cost of CO2 captured is \$23-35/tCO_2 for PC and \$11-32/tCO_2 for IGCC. Hence, there has been a considerable focus on commercially deploying IGCC for this reason. However, for low-rank coals (high-moisture, sub-bituminous coals), the economics of post-combustion capture in PC plants is similar to, or cheaper than, the economics of carbon capture in IGCC plants (Holt, 2006). Also, there is significant overlap in the cost ranges between PC and IGCC technologies and this overlap is expected to increase in the future as PC technologies become more efficient and the use of oxyfuel combustion become more commercial (see Table 34). Although the cost of the capture plant is a significant part of the base cost of NGCC plants, NGCC plants with post-combustion capture remain the cheapest option in terms of COE when compared to coal-based plants[383] (see Table 33).

Performance	Past	Present		Future			
		Best available technology		2010-2015		2015-2025	
	Typical Conditions	PC	IGCC	PC	IGCC	PC	IGCC
Capital Cost US$/kW		1000 – 1200	1200 – 1500	900 – 1100	1000 – 1200	900 – 1000	800 – 1000
Efficiency (% HHV)	33 – 35	40 – 43	40 – 44	45 – 50	45 – 50	50 – 53	50 – 60
Efficiency loss for 90% CO_2 capture		7 – 12	6 – 8	4 – 7	4 – 5	2 – 4	2 – 3
Capital Cost for CO_2 capture (US$/kW)		700 – 900	300 – 800	500 – 600	200 – 500	300 – 400	100 – 300
COE without capture (US cents/kWh)		3.5 – 4.4	4.4 – 4.9	3.0 – 4.1	3.0 – 4.1	< 3.0	< 3.0
COE w/ capture (US cents/kWh)		6.3 – 7.9	5.7 – 6.4	3.6 – 4.9	3.3 – 4.5		

Table 34: Expected future performance and costs of PC and IGCC technologies. Source: (CETC, 2005).

Retrofitting and rebuilding are other important considerations for choice of base technology. This is a particularly important issue for countries, such as India and China, which are poised to install large amount of new capacity in the coming years. For pulverized coal plants, detailed engineering-based retrofitting and rebuilding studies have only on done on subcritical PC units (Bozzuto et al., 2001; Simbeck, 2001). Retrofitting amine scrubbing technology to an existing PC plant would reduce the electrical output from 500 MW to about 300 MW—a derating of

[383] This is only true if NGCC plants are operated at high capacity factors and not used for meeting peak load.

about 40%--and the efficiency decrease is about 14.5 percentage points, compared to the loss of 9.2 percentage points for a Greenfield subcritical PC with capture (Bozzuto et al., 2001; MIT, 2007). The higher losses in retrofitting is due to the additional steam requirement for the capture process—the loss of steam implies that the original turbine is now running at about 60% design rating, which is off its efficiency optimum (MIT, 2007). The incremental capital cost of the MEA retrofit is quite high—about $1600/kW—because of the severe derating (Bozzuto et al., 2001). As opposed to retrofitting, one can also rebuild (or repower) an existing PC plant with supercritical or ultrasupercritical PC technologies along with carbon capture. This option can maintain the same power output while being more efficient than a retrofit. Although the total capital cost is much higher (as the entire plant has to be redone, as opposed to the end-of-pipe retrofit option), the cost of electricity is similar to that of a Greenfield PC with capture (MIT, 2007).

While PC technology is more amenable to retrofitting in the future (albeit with higher cost and energy penalties), retrofitting IGCC power plants is more complicated. Retrofitting PC plants primarily requires additional space for capture equipment and the ability to extract low pressure stream, and it does not affect the boiler section of the plant (unless one considers rebuilding or repowering). In contrast, retrofitting an IGCC plant for optimum CO_2 capture requires drastic changes to the gasifer itself (MIT, 2007).[384] The choice of the entrained-flow gasifier (slurry-feed or dry-feed), gasifier configuration (full-quench, radiant cooling, or convective cooling), type of acid-gas cleanup,[385] gasifier operating pressures, and the kind of gas-turbine (i.e. one designed for low-BTU syngas or high-BTU hydrogen-rich gas) depend on whether a no-capture or a capture plant is built (Stephens, 2005; MIT, 2007). An optimized no-capture design would be based on dry-feed (Shell),[386] lower pressure (2.8-4.1 MPa) gasifier with radiant or convective syngas coolers in order to increase the generation of steam, which in turn increasing generation efficiency. In contrast, a capture design would be based on a slurry-feed (GE), high pressure (6 MPa) to reduce costs of CO_2 capture, recovery and compression and full-quench design in order to increase the steam content in the raw syngas for the water shift reaction. Thus, retrofitting an IGCC plant optimized for no-capture would require significant changes to nearly all components (unlike a PC plant), and therefore investment in a "capture-ready", non-capture IGCC plant may not make too much sense.[387] In other words, if one is considering IGCC has a base technology for capture, it would be better to simply design and built an optimized IGCC-capture plant right away, rather than plan for retrofitting at a later stage.

Thus, the uncertainties in R&D and technology development in gasification and combustion technologies does not allow us to make definitive statements about which technology is (or will be) better for reducing the cost of carbon capture for both Greenfield and retrofit/repower applications. A specific assessment has to be made on a project-by-project basis. However,

[384] Corresponding changes will also have to be made to the combustion and power generation train of the IGCC.
[385] A typical no-capture IGCC would covert COS into H_2S in a catalytic bed, and then the H_2S is removed using a physical solvent such as Selexol. In a capture IGCC, the COS conversion can be eliminated as COS is converted to H_2S in the water-shift reactor, and H_2S and CO_2 can both be removed by a Selexol process (Stephens, 2005).
[386] A slurry-fed GE gasifier with radiant coolers is also well favored for no-capture IGCC plants. The dry-feed Shell gasifier has highest efficiency and is favored for coals with lower heating value, although the capital cost is higher than the GE gasifier (MIT, 2007).
[387] One could, of course, still leave space for the water shift reactors and allow for steam extraction in a no-capture IGCC plant, in order to make it more 'capture-ready'.

current best estimates indicate that the standard PC technologies using post-combustion capture is likely to be more expensive than IGCC with pre-combustion capture in the United States and Europe. Furthermore, there are only few studies for post-combustion capture with fluidized bed combustion and there are no detailed studies for IGCC-based carbon capture using fluidized bed or moving bed gasifiers—technologies that are most relevant for India.

6.6.1.2 Value of carbon dioxide

The costs of carbon capture can be compensated if it can be sold as a commodity by power plants that capture CO_2. Compressed CO_2 already has value in enhanced oil recovery (EOR),[388] which is a well established technique for extending the life of oil fields.[389] There are more than 70 CO_2-EOR projects in the United States, producing around 200,000 barrels per day by injecting about 30 million tons of CO_2 into depleted oil fields (EPRI, 1999; IPCC, 2005). Although most of the current projects rely on natural CO_2 sources, use of captured CO_2 is now being explored. The price of CO_2 for EOR can be indexed to the oil prices, with price for a ton of CO_2 being about 65% of the price of a barrel of oil[390] – which would be about \$45/tCO_2 for oil prices of \$70/barrel. However, it is important to note use of CO_2 for EOR is a niche market for storage, and is primarily useful for gaining operational experience for CCS. Another approach for evaluating the value of CO_2 is based on sequestering the CO_2 from power plants by reforestation. Such an approach gives a value between \$70-300/tCO_2 and the value of reducing CO_2 emissions of coal power plants to be about 0.68¢/lb of CO_2 (Ottinger et al., 1990).

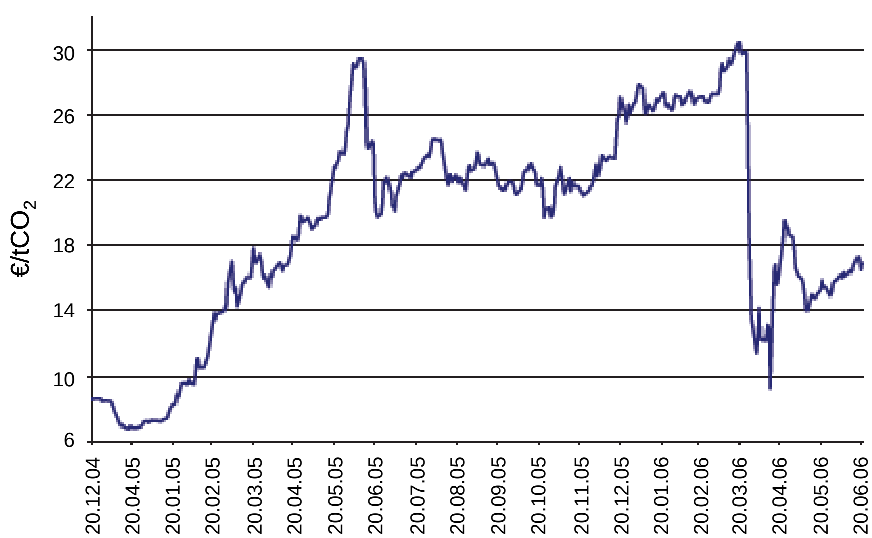

Figure 43: Price of CO_2 traded in the EU ETS. Source: (Point Carbon, 2006b)

---

388 Enhanced oil recovery is a process wherein carbon dioxide can be injected into depleted oil wells to extract oil out of otherwise abandoned reservoirs.

389 Standard primary and secondary petroleum extraction techniques can remove between 20-40% of the oil present in a reservoir. EOR can increase the recovery to 30-60% or more. See: http://www.fe.doe.gov/programs/oilgas/eor/

390 An indicative price of CO2 is 11.7 US\$/tCO2 (0.62 US\$/Mscf) at a West Texas Intermediate oil price of 18 US\$ per barrel, 16.3 US\$/tCO2 at 25 US\$ per barrel of oil and 32.7 US\$/tCO2 at 50 US\$ per barrel of oil (IPCC, 2005). The effective price of CO_2 can also be set by taxes imposed CO_2 emission, incentives provided for CO_2 capture, tax rebates, etc.

In January 2005, the European Community began participating in a carbon trading system (ETS), whereby nearly 12,000 carbon emitting industries (accounting for about 44% of European CO2 emissions) trade EU emission allowances (EUAs) in order to meet sector-specific emission limits (Point Carbon, 2006a). The allowances are allocated to the industries based on National Allocation Plans – nearly 55% of the allowances are for power and heat industries – allowances equaling nearly 1.8 $GtCO_2$ are allocated yearly from 2005 to 2007. In 2005, about 360 MT of CO2, worth about €7.2 billion was transacted in the ETS (Point Carbon, 2006a). The price of carbon rose from an initial €7/t before settling in the range of €20-30/t until end of April 2006, when the carbon price dropped dramatically (see Figure 43) (Point Carbon, 2006b). This sudden drop was precipitated by lower than expected emissions from several member countries and it has led to some discussions on viability of the ETS scheme (Open Europe, 2006; Point Carbon, 2006b).

The relatively high price for CO_2 in the ETS has led to a robust CDM market as well.[391] As of now, more than 250 CDM projects have been registered, worth nearly 73 million certified emissions reduction units (CERs); and more than 900 projects are in the pipeline.[392] As noted in section 3.4.2, India has been taking a renewed interest in CDM projects – nearly 30% of registered projects worth about 10 million CERs from India.[392]

6.6.2 Carbon capture in India

Technologies for capturing of CO_2 can be considered as yet another pollution reducing equipment (see Table 31); however, CO_2 is not yet considered as a pollutant in India (as well as in many other industrialized countries) and capturing CO_2 from power plants is inexorably linked to the larger political process of mitigating global climate change. Nonetheless, the Indian power sector can take to prepare itself for the possibility of carbon capture by: a) better cleaning of pollutants from flue gases and b) installing high efficiency power plants. Economic carbon capture in Indian power plants will require low pollutant levels in flue gas and high power plant efficiency. In the amine-scrubbing process, excess SO_x and NO_x in the flue gas will permanently bind itself to the amine and reduce the amine's absorptive property for CO_2 and increasing the risk of solid formations in the amine solution (see section 6.6.1). It also results in excess consumption of chemicals to regenerate the solvent and produces high waste streams (IPCC, 2005). Hence, it is important to clean these impurities from the flue gas to very low levels before attempting carbon capture. Given the relatively low emission standards for flue-gas emissions and the problems with enforcing these standards in India, the first step towards carbon capture is tighter, enforceable environmental laws on local air pollutants. Effective carbon capture is only possible when it can be based on institutional and regulatory structures that are created to strongly enforce local pollution standards.

Furthermore, it is important to recognize that retrofitting carbon capture equipment to existing plants will significantly alter plant design, efficiency and economics (for both PC and IGCC plants), such that only high-efficiency plants can be considered for carbon capture retrofitting.

[391] As specified under the Kyoto Protocol, the Clean Development Mechanism (CDM) allows for investors in industrialized countries to receive Certified Emissions Reduction units (CERs) for the actual amount of greenhouse gas emissions reduction achieved through CDM projects undertaken in non-Annex 1 countries. See: http://unfccc.int/kyoto_mechanisms/cdm/items/2718.php.
[392] http://cdm.unfccc.int/Statistics

Carbon capture will increase auxiliary consumption and the cost of generation and the efficiency penalty for installing CO_2 capture equipment is high, particularly for retrofitting in PC plants. Installing capture equipment onto the best existing technology (i.e., the 500 MW units) would likely reduce the net power output and the net efficiency would likely reduce from the current 33% to about 22%.[393] Sonde (2005) has estimated that 65 MW (30%) will be lost in a 210 MW unit if equipped with MEA post-combustion capture technology, and that efficiency loss would be 30%. Carbon capture will also increase the cost of power generation in India, due to losses in net power and efficiency and the need to add better cleanup technologies prior to carbon capture, in addition to the cost of CO_2 capture equipment. It is estimated that an amine-based capture technology would increase the total operating cost of a 210 MW power plant by Rs. 1500-1700/tCO_2 (Sonde, 2005), which will add an additional Rs. 1.7-1.9/kWh – almost doubling the cost of power. Such high costs and loss in net power and efficiency implies that it is crucial to install high efficiency power plants as a precursor to any possible retrofitting for carbon capture.

In addition, even in the case of IGCC, most of the studies related to carbon capture have been limited to entrained flow gasifiers (as discussed earlier), and there are no detailed studies for capture from fluidized bed or moving bed gasifiers. Hence, there is a great need for detailed studies of carbon capture (including retrofitting options) in future Indian IGCC plants, especially for those based on fluidized-bed gasifier technology.

On the other hand, assessing carbon capture for PC plants in India is relatively simpler.
Finally, large-scale deployment of carbon capture equipment in power plants will only occur when there is a political will and drive to deal with climate change; such a political thrust is currently non-existent in the Indian polity (as discussed earlier). In addition, the high losses in net power and efficiency would be difficult to accept in a situation with electricity and coal shortages. Therefore, it is unlikely that the Indian power sector will move towards capturing CO_2 in the short-to-medium term, although small pilot-scale research and demonstration activities could be conducted in test to assess feasibility of capture in Indian conditions.

6.6.3 Storage options

Once CO_2 is captured from power plants (or from other industrial processes), it has to be transported to a 'permanent'[394] storage location – such that it does not add to the atmospheric concentration. There are several different options for carbon storage[395]: a) ocean storage by pumping CO_2 deep into the bottom of the ocean, b) chemical storage by binding CO_2 with other chemicals to form an inert substance, and c) geological storage by pumping CO_2 underground into depleted oil and natural gas reservoirs and in deep saline reservoirs. Of the three, geological storage is the most promising for power plants, and hence this option will be discussed in more detail (see Box 4 and 5 for brief descriptions of ocean and chemical storage).[396]

---

[393] The average efficiency loss for retrofitting capture equipment on existing power plants is 34% (IPCC 2005: Table 3.8).
[394] The CO_2 will have to be stored away for hundreds of years or more, which is practically permanent.
[395] Biological sequestration (enhancing of natural sinks such as forests and soil) is not directly applicable to power plant emissions.
[396] Storage of CO_2 also involves the transportation of the gas to storage locations through pipelines (expect perhaps for chemical storage, for which a carbonation plant can be built on location). It requires the CO_2 to be compressed into a liquid under high pressure. There are various issues and problems with CO_2 pipeline transportation, which are discussed in the IPCC (REF) report.

Box 5: Ocean storage

Ocean storage involves the transportation of CO_2 via pipelines or ships and injecting it into the deep waters or sea beds. The viability of ocean storage has not yet been demonstrated in a large scale, although there has been some theoretical, laboratory and modeling studies. The ocean has already absorbed about 50% of the total anthropogenic carbon emissions over the past 200 years, and it is already becoming more acidic (IPCC, 2005). Technically, there is practically no limit to the storage capacity in the oceans, and the stored CO_2 can be isolated from the atmosphere for several hundreds of years.[397] Cost estimates of ocean storage are in the range of $5 – 30/tCO_2$, including the cost of transporting the CO_2 100-500 km offshore (IPCC, 2005).[398]

However, the environmental impacts of ocean storage are enormous. It is quite clear already that increased CO_2 levels in the ocean adversely affects marine biology and present understanding of long term impacts on deep ocean ecosystems is very limited (IPCC, 2005). Furthermore, public perception appears to be against ocean storage, in contrast with geological storage (IPCC, 2005). Hence, ocean storage is currently not an option for storing CO_2 from power plants.

Box 6: Chemical storage

Chemical storage involves fixing the CO_2 to alkaline and earth-alkaline oxides that are present in natural silicate mineral rocks[399] to form carbonates and silica. This chemical reaction is the most permanent method for storing CO_2, as it is an exothermic reaction. The technology for mineral carbonation is not yet mature to allow for a proper assessment of costs and performance; nonetheless, there is interest in chemical storage because the vast quantities of silicate mineral rocks present in the Earth's crust is more than enough to permanently store all of CO_2 that can be generated by fossil fuel reserves.

There are two options for mineral carbonation: in-situ and ex-situ carbonation. In-situ carbonation involves the injection of CO_2 directly into the silicate rich mineral deposits underneath, and it can be considered as one of the mechanism for geological storage. Ex-situ carbonation involves setting up of a separate carbonation plant wherein natural silicates or alkaline industrial waste are processed and prepared for carbonation with the captured CO_2 – about 2-4 tons of silicate will have to mined to store a ton of CO_2 (IPCC, 2005). Direct reaction between gaseous CO_2 and solid mineral is unfeasible at present, and hence the minerals have to be put in an aqueous solution into which CO_2 can also be dissolved. The resultant carbonate and silica can then be precipitated out of the solution. Although the carbonation reaction is exothermic,[400] the pre-processing procedures, including mining, will require a significant amount of energy input. Large quantities of by products, about 3-5tons of silica and carbonates per ton of CO_2, will have to be properly disposed off.[401] The key environmental impacts will be in the mining of the minerals, preparing the ore, and disposing the waste; and as such the impacts will be the same as for any other mining operation – land clearing, air pollution, tailings, reclamation, etc.

---

[397] The potential for longer storage increases with deeper injection (IPCC, 2005).

[398] These costs do not include the cost of piping the CO_2 to the shoreline or the monitoring costs after injection.

[399] Natural silicates include rocks with minerals such as serpentine, olivine, enstatite, talc, etc.

[400] The kinetics of the carbonation process can be slow; thereby, the silicates have to be heated to enhance kinetics.

[401] The waste can be either put back into the mines or be used as landfill, road fill and other industrial purposes.

The estimated cost of ex-situ mineral carbonation is quite high – about \$50-100/tCO_2 net mineralized (IPCC, 2005). Although still at an early stage, the high costs and environmental impact of mining/disposal might limit widespread use of ex-situ mineral carbonation.

6.6.3.1 Geological storage

Injection of CO_2 in deep rock formations below the Earth surface[402] – i.e., geological storage – is becoming an important option for storing CO_2 captured from power plants. CO_2 can be injected into geological formations such as oil and gas reservoirs, deep saline aquifers, unmineable coal beds, and deep water-saturated mineral rocks. Prior to its injection, the gaseous CO_2 has to be compressed into a dense, high pressure, 'supercritical' state.[403] The Earth's sub-surface already has plenty of carbon stored in it as coals, oil, gas, oil-rich shales, and carbonate rocks. So, in some sense, geological storage can be considered as returning the carbon back underground after utilizing its stored chemical energy for human activity.

Underground injection of CO_2 has commercialized since the 1970s for enhanced oil recovery (EOR) – wherein CO_2 and water have been periodically injected to extract more oil out of a reservoir. Although injecting CO_2 for EOR is not specifically meant for storage, a fraction of the injection CO_2 (30-50%) does remain captured in the reservoir. Commercial-scale CO_2 storage projects are also already underway in Norway (North Sea), Canada (Weyburn), and Algeria (In Salah), [404] with many future projects more planned in Canada, China, Australia, U.S.A., Poland, Japan, Netherlands and Norway (IPCC, 2005). The technology for injecting gases into geological media is well established,[405] and it requires many of the same technologies developed in the oil and gas exploration and production industry.[406]

Geological formations most suitable for storage are in sedimentary basins,[407] wherein the subsurface has mineral rock formations, organic matter, cavities and fissures. The pore spaces, cavities and open fractures are mainly filled with water and with oil and gas in a small number of locations worldwide. When CO_2 is injected into these formations, the gas can undergo a number of transformations – it can diffuse and displace existing fluids, mix or dissolve with the existing fluids, chemically react with minerals present in rocks, adsorb onto organic material, be trapped in pore spaces by capillary action, or a combination of all these processes. The primary mechanisms of storage include (IPCC, 2005):

---

[402] Deep formations are those below 800 m from the surface (IPCC, 2005).

[403] Similar to the water-steam supercritical conditions, the critical temperature of CO_2 is 31.1^{o}C and the critical pressure is 7.38 MPa (72.8 atmospheres). Above this temperature and pressure, the CO_2 is gas-like, but with high densities of a liquid. Generally, CO_2 remains supercritical below 800 meters underground.

[404] The Sleipner project in the North Sea (Norway), the Weyburn project in Canada and the In Salah project in Algeria are injecting more than a million tons of CO_2 per year into the ground. For a description of these projects, see Chapter 5 of IPCC 2005.

[405] Fluids have been injected into the deep subsurface for a long time to dispose of unwanted chemicals, pollutants, and petroleum by-products to enhance oil and gas recovery. Natural gas has also been injected and stored in sub-surface reservoirs in many places (IPCC, 2005).

[406] These technologies include well drilling, injection, reservoir capacity/storage assessment, simulation of reservoir dynamics, monitoring methods, etc.

[407] The World's geological provinces can be divided into simplified categories – sedimentary basins, shields, highs and fold-belts (Bradshaw and Dance, 2004).

- Physical trapping: The injected CO_2 is trapped by cap-rocks of low permeability, such as shale, salt beds, or gas hydrates. Many of the physically bound traps that contain oil or natural gas can also physically trap CO_2.
- Hydrodynamic trapping: The gaseous CO_2 injected into saline formations will be trapped in saline because of the very slow upward migration of the gas through the aquifer (timescale of tens to hundreds of years or longer[408]). The upward migration occurs because of the buoyancy of CO_2 gas in water. Once fully migrated to the top of the saline reservoir, the gas can be physically trapped. At longer times (thousands to millions of years) the gas will slowly dissolve into the saline (solubility trapping) or be mineralized (geochemical trapping).
- Solubility trapping: As the gaseous CO_2 dissolves in the water, it becomes converted into a weak carbonic acid. The dissolution will prevent the upward migration since the CO_2 is no longer in a separate phase.
- Geochemical trapping: The carbonic acid, formed when CO_2 is dissolved in water, can react with minerals in the rock formation to form carbonates. The chemical reaction to carbonates is the most permanent form of storage.[409]
- Adsorption trapping: Injecting CO_2 into coal seams or organic-rich shales might result in CO_2 being bound to micropores in coal, shale and other surfaces. CO_2 has a greater affinity for coal than other gases such as methane; hence, CO_2 injection can be used to enhance the extraction of coal-bed methane along with CO_2 storage in the coal bed. Adsorption might eventually lead to absorption and dissolution of CO_2 in the coal – changing the structure of coal itself (IPCC, 2005).

Prior to injection, a baseline survey and monitoring of the reservoir is necessary to ensure that proper monitoring can be performed after injection. Monitoring and verification of CO_2 storage and movement of CO_2 underground is essential in order to ensure it remains trapped or take action if leaks occur.[410]

6.6.3.2 Storage locations and capacity

The sedimentary regions are not evenly spread across the Earth's surface. The distribution of sedimentary regions along with the prospectivity of CO_2 storage[411] is shown in Figure 44. The prospectivity of storing CO_2 generally increases when sedimentary regions are in mid-continent locations, at the edge of stable continental plates, or behind mountains formed by colliding plates. Geological regions that already have world-class petroleum reserves are among the best places to store CO_2. However, the potential to store CO_2 and the storage capacity are not determined by the mere presence of sedimentary basins or their geographical size (surface area). The surface area of a basin is not correlated with either current hydrocarbon storage (such as petroleum reserves) or CO_2 storage potential (Bradshaw, 2005). Instead, each prospective basin has to be individually assessed for storage capacity and for ability to inject CO_2.

---

[408] Where the distance between injection point and the region of impermeable layer may be hundreds of kilometers, the hydrodynamic trapping time (CO_2 migration time) can be millions of years (Bachu et al., 1994)
[409] Geochemical trapping is the same as in-situ chemical storage discussed in Box 4.
[410] If leaks do occur, there are many remediation options for minimizing the impact of leaks and to seal the leaks (IPCC, 2005).
[411] Prospectivity is a qualitative assessment of the likelihood that a suitable storage location is present in a given area based on the current available information (IPCC, 2005).

Key criteria for assessing suitability of basin for CO_2 storage include (IPCC, 2005):

- basin characteristics (tectonic activity, sediment type, geothermal and hydrodynamic regimes);
- basin resources (hydrocarbons, coal, salt);
- exploration of possible fossil fuel resources in the basin, along with industrial maturity and infrastructure; and
- societal issues such as level of development, economy, environmental concerns, public education and attitudes.[412]

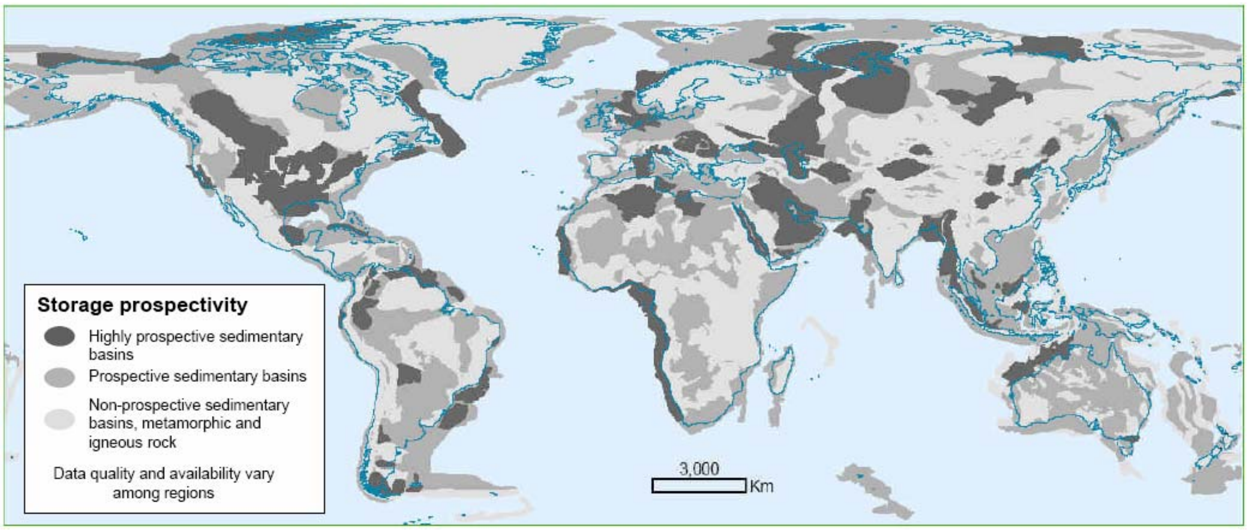

Figure 44: Prospectivity of CO_2 storage locations. The various geological provinces are categorized into highly prospective (world-class petroleum basins), prospective (minor petroleum basins, less-deformed sedimentary basins) and non-prospective basins (shields, fold-belts, etc.). Source: Figure 2.4 of IPCC 2005..

Mature, well-explored sedimentary basins are the best prospects for finding CO_2 storage sites. Some of the main storage sites for CO_2 capture include:

1. <u>Abandoned oil and gas reservoirs</u>: These are prime candidates for CO_2 storage because of their historically demonstrated structural integrity (by storing hydrocarbons in physical traps, sometimes for many millions of years). They have also been extensively characterized and modeled; in some cases, infrastructure for drilling might still exist.[413]
2. <u>Enhanced oil and gas recovery</u>: Reservoirs with extractable oil and gas can be injected with CO_2 and water to push the oil and gas out of the reservoir. Such operations have enormous economic and energy security value, in addition to CO_2 storage.

---

[412] Within a basin, any particular storage site should generally have (IPCC, 2005):

- adequate capacity and injectivity – the injection site should be porous enough to allow for CO2 to diffuse into the rocks and thick enough to have enough capacity;
- a satisfactory sealing cap rock – the storage formation must be capped with extensive confining units with low permeability, such as shale, salt or anhydride beds, to ensure that the injected CO2 does not simply diffuse up to the surface; and
- a sufficiently stable geological environment – the integrity of the storage site should not be compromised by highly faulted and fractured sedimentary basins (particular attention must be paid for sites in seismic areas).

[413] With extensive drilling, some wells need to be properly sealed using clay or cement plugs.

3. Saline formations: These are deep sedimentary rocks with formation waters or brines with a high concentration of dissolved salts. As discussed earlier, the injected CO_2 will be initially trapped by hydrodynamics, and eventually by solubility trapping and mineralization.
4. Unmineable coal seams: Coal seams that are inaccessible to mining can be used to store CO_2 using adsorption trapping.[414] Coal also has a higher affinity to adsorb gaseous CO_2 than methane, and hence CO_2 injection can help enhance coal bed methane (CBM) recovery. Generally, a coal bed's permeability decreases with increasing depth and hence CBM wells are less than a kilometer deep. Furthermore, higher coal rank might enhance the relative adsorptive capacity of methane and CO_2 (Reeves et al., 2004).
5. Oil or gas rich shale: Trapping of CO_2 in organic-rich shale is similar to that in coal beds. The potential for storage is unknown, although deposits of shale occur in many parts of the world.
6. Basalts: Flows and layered intrusions of basalt occur globally with large volumes. Although basalt has low permeability and low porosity, there is some possibility of mineral trapping of CO_2 in basalt, although current science does not clearly indicate that the suitability of basalts for CO_2 storage.

	Estimates Storage Capacity (including uneconomic options)	
Reservoir Type	Lower estimate ($GtCO_2$)	Upper estimate ($GtCO_2$)
Oil and gas fields	675	900
Unmineable coal seams (CBM)	3 – 15	200
Deep saline formations	1000	Uncertain, possibly 10,000

Table 35: Estimates of Global CO_2 storage capacity in geological reservoirs. The storage estimates make many simplifying assumptions and the results have many caveats. Source: Adapted from (IPCC, 2005)

Estimates of storage capacity in oil and gas fields, saline formations, and in unmineable coal seams are quite uncertain because of lack of data and unavailability of resources to conduct proper assessments. The IPCC (2005) has summarized the low and high best-case estimates of storage capacities, including uneconomical storage options (reproduced in Table 35). The estimates in oil and gas fields and saline aquifers indicate that there is plenty of storage space -- even if all of the current annual emissions of approximately 25 $GtCO_2$ are to be captured and stored geologically.

Another important issue with geological storage is the matching of sources with storage sites. There are currently more than 7500 large stationary sources (LPS) of CO_2 (> 0.1 $MtCO_2$/year) worldwide and these sources are not necessarily located in close proximity to potential storage sites. According to Bradshaw and Dance (2004), a simple analysis of comparing the prospective CO_2 storage sites with locations of CO_2 emitters indicates that many of the LPS are close enough to potential high storage options (in U.S., Europe, Australia, Canada, South-east Asia, South America, etc.), whereas other regions have low storage options and less matching of LPS with potential storage sites (in China, India, Japan, Russia). Siting of future LPS in various countries might need to consider potential storage locations as well, in order to facilitate CCS.

[414] It is important to ensure that coal bed CO_2 storage does not conflict with possibilities for in-situ gasification.

6.6.3.3 Risks and costs of storage

All activities, including geological storage, have environmental impacts. The key impacts of improper or leaky geological storage involve global risks, such as release of CO_2 that will accelerate the impacts of global climate change, and local risks, such as CO_2 leaking into groundwater and local ecosystems that affect humans and local terrestrial systems. The global risk of CO_2 leakage is minimal because it is expected that geological storage, if done correctly and properly monitored, can store 99% of the injected CO_2 for over 100 years or more (IPCC, 2005). Local risks include sudden release of CO_2 because of injection well failures or up abandoned wells, and slow leaks through undetected faults, fractures or wells. In the former case, sudden CO_2 release can be detected and stopped quickly using current technology. In the latter case, slow leaks could affect drinking water aquifers, soils, and local terrestrial ecosystems (if in low-lying areas with little wind). Careful siting and design of storage sites, combined with effective monitoring of CO_2 migration (CO_2 sensors, seismic surveys, etc.) and early detection of leaks, there remediation techniques to stop or control these slow leaks.[415]

The cost of storage in geological subsurface varies according to site-specific factors such as onshore vs. offshore, reservoir depth, geological characteristics, etc. Representative cost estimates in saline formations and depleted oil and gas reservoirs are between \$0.5-8/tCO_2 injected, with an addition \$0.1-0.3/tCO_2 for monitoring and verification (IPCC, 2005). When CO_2 storage is combined with EOR or CBM, the economic value of CO_2 can result in a net benefit for injecting CO_2 underground.[416]

6.6.4 CO_2 storage locations in India

Potential storage sites in India might exist in the Gangetic, Brahmaputra and Indus river plains, and along the immediate offshore regions in the Arabian Sea and Bay of Bengal (IPCC, 2005). A preliminary estimate of storage capacity by Dooley and Friedmann (2004) indicate that about 385 GtCO_2 might be stored in Indian sedimentary basins, although only 14 GtCO_2 (4%) of storage is expected to be in oil, gas, and coal bearing regions. Much of the storage (96%) is in on-land and off-shore saline reservoirs. A more recent estimate indicates that about 360 Gt of potential storage exists in onshore and offshore deep saline reservoirs, 7 Gt in depleted oil and gas fields, and 5 Gt in unmineable coal seams (Singh et al., 2006).[417]

Geological exploration and assessments are necessary for not only CO_2 storage, but also for identifying new hydrocarbon and coal resources—thereby, enhancing energy security. However, However, Indian sedimentary basins, in general, are not yet well-explored geologically, with only about 18% of the 3.14 million square km being moderate-to-well explored, with 30% completely unexplored and more than 50% of the basins being either poorly explored or under preliminary exploration.[418] A map of Indian sedimentary regions is shown in Figure 45, color-coded to indicate the current level of exploration in these basins. Much of this current

[415] Also, with more storage projects, experience can be built up to deal with these risks.
[416] Data for onshore EOR indicates a net benefit of \$10-16/tCO_2, including costs of geological storage. With the price of oil and gas increasing, the economic value of CO_2 might even be higher (IPCC, 2005).
[417]
[418] India has 26 sedimentary basins with 1.78 million sq. km within the 200 m isobath (1.39 million sq. km, onshore; 0.39 million sq. km, offshore), and the rest in deep water (DGH, 2004). Exploration of these basins is governed by licensing policies established by the government.

exploration is mainly for hydrocarbon and coal resources. However, basins suitable for CO_2 storage may not always be hydrocarbon rich. For example, the Gangetic basin, below the Himalayan range, is relatively unexplored because it does not have much potential for hydrocarbon resources. But, on the other hand, this basin is particularly suitable for CO_2 storage in underground saline reservoirs, and much of the estimated on-land storage capacity estimated by Dooley and Friedmann (2004) is in this basin. Hence, there is an enormous amount of specific geological work that needs to be done for assessing CO_2 storage sites, as well as for exploring new hydrocarbon and coal resources.

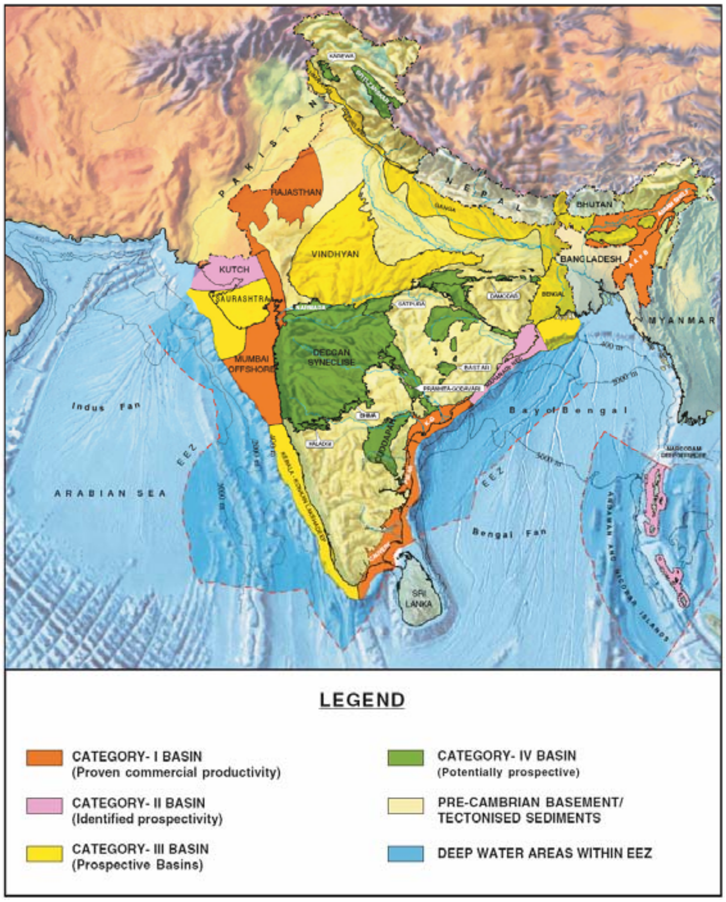

Figure 45: Major sedimentary basins of India. Some of the major sedimentary basins are shown above, categorized according to the current exploration level of hydrocarbons. Category I – established commercial production; II – known accumulation of hydrocarbons with well-to-moderate exploration, but with limited or no commercial production; III – indicated hydrocarbons that are considered geologically prospective, with active exploration; IV – uncertain potential that may be prospective; limited exploration. With more exploration and new mining being undertaken, the map will continue to change. Source: (DGH, 2004).

While there is a large potential for storage in saline reservoirs, it is important that current data from hydrocarbon exploration be used to assess the feasibility of using the already-well-mapped oil and gas reservoirs for CO_2-based enhanced oil and gas recovery. India's total hydrocarbon resource is estimated to be about 28 billion tons of oil and oil-equivalent of gas (DGH, 2004), of which the proved and indicated reserves were shown in Table 9. Although most of the actual oil production is currently from onshore basins, offshore basins are being extensively explored for oil and natural gas finds.[419] Also, in 2000, an estimated 25% of the oil and gas wells in India were dry and many more on the verge of being dry (Garg et al., 2004). Hence, CO_2-based EOR might serve to extract more oil out of these wells and be an important demonstration of CCS in India.

Furthermore, many of the eastern Category-IV sedimentary basins are coal-bearing areas (compare Figure 25 with Figure 45). Some of these coal bearing areas have potential for CO_2 storage in deep unmineable coal seams and also for CO_2 enhanced coal bed methane (CBM) recovery.[420] Based on current estimates, about 7% of the coal resources (18 billion tons) are below 600 m (see Table 16). Much of this coal cannot be mined and hence might be used for CO_2-based enhanced CBM and/or in-situ gasification.

Finally, although a significant portion of southern India is a shield, there might be some potential for storing CO_2 in basins beneath the basalts of the Deccan Syneclise in West Central India. Currently, surveys are underway to assess possibilities of hydrocarbon finds underneath the Deccan Trap, more than 2-3 km deep in some places (DGH, 2004). The sedimentary basins underneath the basalt might be potential storage sites for CO_2, since the basalt can act as a cap-rock (physical storage) and provide minerals for carbonation (geo-chemical storage). In addition, there is also potential for CO2 storage in basalts itself, although such storage is largely untested and there is substantial scientific debate surrounding storage in basalts and other storage media.[421] Nonetheless, it might be a possible storage option for CO_2 in central India.[422] Singh and collaborators (2006) have estimated that a potential storage capacity of 200 Gt in basalt formations.

It is estimated that only about 43% of India's current CO_2 emissions from stationary sources might have potential CO_2 storage sites within a 300 km buffer zone (IPCC, 2005).[423] Other studies have also indicated that only some of the top 20 large point sources in India are within 200 km of potential storage sites, although all of them are within 500 km of potential sites (Garg et al., 2004). Given that India might have problems locating good CO_2 storage sites near its current stationary sources, it is essential that proper assessments of storage capacity must be undertaken immediately – particularly in the on-land and off-shore saline reservoirs – and future power plant sitings should take CO_2 storage locations into account, even before carbon policy is in place, given the long lifetime of power plants.

[419] About a million sq. km is currently under exploration (primarily by ONGC), of which 78% is offshore exploration. However, only about 19,400 sq. km of area is under mining and production (50% ONGC, 25% OIL), with 63% of the mining on land-based basins (DGH, 2004).
[420] More than 8000 sq. km in the coal bearing regions has already been allocated for CBM exploration and subsequent development. It is expected that about 820 billion cubic meters of gas might be accessible in these areas, with a production capacity of 23 million standard cubic meters per day (DGH, 2004).
[421] Personal communication, J. Friedmann (2006).
[422] As part of the Carbon Sequestration Leadership Forum, laboratories in India and the United States are already assessing storage possibilities in basalt, with support from NTPC (Sonde, 2005).
[423] This estimation is based on surface area assessment of sedimentary basins. However, surface area studies are fundamentally unreliable, as it does not take geology in account (Bradshaw, 2005; IPCC, 2005).

7 Technology Comparisons

Having analyzed the current status and possible future trajectories for key coal power technologies, we now compare the key performance characteristics of these technologies and use a simple rating scheme to fold the performance characteristics along several dimensions to a single value that helps rate these technologies in terms of their relevance to our vision for the coal power sector.

7.1 Comparing clean coal technologies

Drawing on the earlier assessment of technologies that we deem to be relevant to the Indian context, a unified view of the key characteristics of these technologies is presented in Table 37.[424] The first few rows in the table indicate the locations in India and worldwide where these technologies are in use or being developed, the major technology manufacturers and developers, the current development status and currently available unit sizes. The next set of rows discusses performance characteristics such as reliability, fuel flexibility, output flexibility, net efficiency and capital costs. The final set of rows describes the various environmental aspects of the technologies. Much of the table is self-explanatory, although some discussion on the efficiency and cost characteristics of these technologies is warranted.

The efficiency of power plants using different technologies is determined either through operational experience (as in the Indian power plants shown in Table 37) or by various studies that estimate expected efficiencies of future power plants that use specific technologies. These include primary engineering-based studies of specific emerging systems (such as Parsons 2002, Marion et al. 2003, or Palkes 2004), synthesis studies that evaluate different engineering studies on a common basis (such as David and Herzog 2000, Rubin et al. 2004, or Marion et al. 2004), or larger technology assessment studies that assess current status and future projections of technologies (such as the DTI studies, Winfield 2004, Lako 2004, PowerClean 2004, or Ghosh 2005). The estimates of efficiency and cost of power technologies are most accurate when based on actual operating/construction experience. Engineering-based studies have the next best estimates, with reasonable confidence levels, and the larger technology assessment and projections have the greatest uncertainties.

Note that published efficiency estimates of power plants using a specific technology (such as supercritical PC or IGCC) vary enormously for many reasons (PowerClean, 2004):

- differences in coal quality and how the heating value of the fuel is calculated,
- differences in site conditions and especially condenser pressure,
- differences in plant design, such as single or double stage reheat when otherwise the plants are of similar design,
- whether gross or net efficiencies (and plant output) are considered, and
- what ‘add-on’ equipments, such as FGDs and SCRs, are used.

[424] Note that underground coal gasification (UCG) is not included in the technology choices that we have chosen to compare, as UCG can be considered more as a mining technology than as a power generation technology.

One common problem that arises when comparing studies is that many times these studies do not properly state whether they are mentioning net or gross efficiencies or whether the efficiency is based on lower heating value (LHV) or higher heating value (HHV) of the input fuel.[425] The ratio of HHV to LHV for a typical steam coal is approximately 1.05. Hence, efficiencies quoted in HHV are lower than those quoted in LHV, even if the technology and site-specific factors are the same. Also, the HHV to LHV ratio varies for biomass and natural gas, leading to further confusion. Although efficiencies based on LHV is truer measure of recoverable energy for coal-based power generation (Booras and Holt, 2004), the use of HHV is common in the United States and Asia. In India, the situation is even worse, since coals are not graded according to their specific calorific value. Nonetheless, the quoted efficiencies are generally in HHV.

Site-specific factors, such as coal properties, ambient conditions, and the temperature and availability of the cooling water, can strongly affect efficiency. The latter issue is particularly important as the final condenser pressure is dependent on effective cooling. Power plants with a condenser pressure of 0.02 bar, which requires a cooling water temperature of 14-15 ^{o}C, can achieve an extra 3 percentage points in efficiency, compared to plants with condenser pressures of 0.05 bar, which corresponds to a cooling water temperature of 27-28 ^{o}C (PowerClean, 2004). Such discrepancies can lead to studies quoting higher efficiencies for power plants in Europe (using cold seawater) compared to U.S.-based plants or Indian plants using the same technology (PowerClean, 2004).

Furthermore, although it is better to compare net efficiencies, rather than gross efficiencies, as the net efficiency includes a plant's auxiliary consumption, the situation is complicated by the fact that auxiliary consumption in power plants of different countries varies depending on the required cleanup of flue gas. The mandated clean-up of the flue gas varies country-by-country. For example, FGDs and SCR are not required in India, whereas these equipments are necessary in Europe, U.S. and Japan, and they lead to increased auxiliary power consumption. Therefore, it is important to have studies that indicate both gross and net efficiencies, as well as state the assumed level of flue-gas cleanup and the energy consumption of add-on pollution control technologies.

As with efficiency, estimates of the levelized cost of electricity (COE) for power plants using different technologies vary widely in published studies, and these estimates have greater uncertainties than efficiency estimates; for example, the Nexant (2003) study has cost uncertainties of ±30%. The key reason for the large variance in the COE estimates is that different studies make different assumptions about the technology and economic/financial factors. Some of these assumptions are shown in Table 36.

[425] The lower heating value (LHV) of a fuel is defined as the higher heating value (HHV) minus the latent heat of evaporation of water contained in the products of combustion. The energy used to evaporate water (latent heat of evaporation) is not usable for power generation, as the heat in the flue gas is generally not recovered below 150^{o}C (Bossel, 2003). While representing the energy content of fuels in HHV is more physically correct, LHV gives a more accurate measurable of recoverable energy for thermal-based power plants. However, there are several issues with the use of LHV for more hydrogen-based fuels. For more information, see (Bossel, 2003).

Technical factors	Plant-related economic factors	Financial factors
‘Greenfield’ or ‘brown field’	Fuel cost	Debt-to-equity ratio
Size of power plant	Capital cost	Interest rate
Net efficiency	Operation and maintenance cost	Expected rate of return
Fuel properties		Tax rate
Use of flue gas cleanup technologies		Inflation rate
Load factor		Plant lifetime
		Construction period
		Cost of labor and construction
		Inclusion of interest during construction
		Inclusion of owner’s cost such as spare parts, land costs, etc.

Table 36: Some key factors affecting the cost of electricity.

In order to make a useful assessment, technologies must be evaluated using engineering-based analyses that reduce uncertainties for performance data. Analyses must also use technical and economic factors/assumptions which are valid in the Indian context, and are the same across various analyses. Such engineering-based comparative assessments for India are lacking, except for the recent Nexant (2003) study, which perhaps is the best available engineering-based study that compares technologies in the Indian conditions, although it does not include the entire spectrum of technologies that we have chosen for comparison. In the Nexant study, calculation of technology performance is based on Indian coal characteristics, the chosen site-specific factors are appropriate for a power plant in Delhi, and air pollutions limits are governed by current MoEF standards. The estimated capital cost for PC and CFBC plants in this study is based on project reports for existing Indian plants PC and CFBC plants, and the rest is based on worldwide experience, appropriately translated to Indian conditions. Hence, the efficiency and capital cost information from the Nexant (2003) analysis is separately shown in Table 37.

The levelized cost analysis of Ghosh (2005) is another useful technology assessment, especially for making relative comparisons between technologies. However, the accuracy of the COE calculations is uncertain as the performance characteristics of the technologies (efficiency, capital and O&M costs) are not necessarily appropriate for Indian conditions.

Technology	Subcritical PC	Supercritical PC (SC-PC)	Advanced / Ultra supercritical PC (USC-PC)	Circulating FBC (CFBC)	Pressurized FBC (PFBC)	Oxyfuel PC/CFBC	IGCC -- Entrained-flow	IGCC -- Fluidized-bed	IGCC -- Moving/Fixed Bed
Use in India:	Almost all Indian power plants	Sipat-I and Barh power plants are under construction.		Surat Lignite and Akrimota Lignite power stations	R&D, pilot scale plant.		Might be useful for using refinery residues.	R&D, pilot scale plant. Plans for demonstration plant.	R&D, pilot scale plant.
Worldwide[i]:	Standard technology worldwide	Europe (Denmark, Netherland, Germany); Japan, U.S., China, Canada	Netherlands, Denmark, Japan	U.S., Europe, Japan, China, Canada	Japan, Demo plants in Europe, U.S.	Development and planned pilot plants in Europe, Australia, Canada. Useful for mainly for CCS.	Demonstration / commercial plants in U.S., Europe, Japan, China	A 6 MW unit in Europe, 100 MW demo plant in U.S. Widespread use for chemicals production and poly generation	Small units in Europe using biomass and waste. Most gasifiers are used for chemicals production
Manufacturers & Technology Developers India:	BHEL, Alstom-India			BHEL, Alstom-India	BHEL			BHEL, CSIR	BHEL, CSIR, IICT
Worldwide:	Alstom, B&W, BWE, Doosan, Foster-Wheeler, MHI, Babcock-Hitachi, Harbin, Shanghai, Dongfang, and many more.	Alstom, B&W, BWE, Babcock-Hitachi, Doosan, Foster-Wheeler, Mitsui-Babcock, Mitsubishi, Steinmuller, Kransny Kotelshchik, Dongfang, Harbin, Shanghai, etc.	Alstom, B&W, BWE, Babcock-Hitachi, MHI, Foster-Wheeler, Toshiba, Dongfang, and others.	Alstom, B&W, Foster-Wheeler, LLB, and others.	ABB Carbon, B&W, LLB, Foster Wheeler, IHI, Hitachi, Mitsubishi.	Alstom, Air Liquide, Foster-Wheeler, Mitsui-Babcock, Praxair, and others	Conoco-Phillips E-GAS, GE-Texaco, Shell, Prenflo, Noell, Mitsubishi	Sasol-Lurgi, Foster-Wheeler, GTI U-GAS, MBEL, HTW, KBR Transport, KRW, TPS.	Sasol-Lurgi, BGL
Level of Maturity	Commercial	Commercial	Commercial / Demonstration	Commercial	Demonstration	R&D / Pilot scale	Gasifier – commercial; IGCC – commercially proven.	Gasifier – commercial; IGCC – demonstration	Gasifier – commercial; IGCC – small pilot plants.
Current Unit Sizes	50 – 1000 MW	250 – 1000 MW	250 – 1000 MW	30 – 400 MW	80 – 350 MW	Similar to PC/CFBC	50 – 500 MW	6 -100 MW	
Performance:									
Output flexibility	Electricity; steam and heat are also possible.				Electricity, steam and heat.	Electricity; steam and heat are also possible	Electricity, syn-gas, chemicals, FT liquids, H_2, steam, heat.		
Fuel feedstock	Hard coal, lignite, fuel oil, petcoke, biomass			Hard coal, lignite, washery middlings, fuel oil, petcoke, biomass, MSW.		Same as PC and CFBC	Hard coal (low ash is better), lignite, petcoke,	Hard coal, lignite, MSW, biomass.	Hard coal, lignite, petcoke, biomass, MSW.

	Subcritical PC	**Supercritical PC (SC-PC)**	**Advanced / Ultra supercritical PC (USC-PC)**	**Circulating FBC (CFBC)**	**Pressurized FBC (PFBC)**	**Oxyfuel PC/CFBC**	**IGCC -- Entrained-flow**	**IGCC -- Fluidized-bed**	**IGCC -- Moving/Fixed Bed**
Fuel flexibility	Can be flexible, with loss in efficiency			Highly flexible. Use of high ash coals supported.		Same as PC and CFBC.	Very flexible, but limited to coals with low ash-content and low ash fusion temperature.	Very flexible, but limited to coals with high ash fusion temperature.	
Reliability; Availability	Excellent; > 85% Availability				Good	Expected to be similar to PC/CFBC	Good. Depends on number of gasifier trains.	Expected to be good. Depends on number of gasifier trains.	
Net Efficiency (net HHV) India:	31 – 34%[ii]; 33%[iii]	35%[iii]		30%[iv]; 33%[iii]	38%[iii]			40%[iii]	
Worldwide:	36-39% (w/o FGD)[v] 37-38% (w/ FGD)[vi]	39 – 41%[vii]	40 – 44%[viii]	34 – 40%[ix]	40%[x]	34% (USC-PC)[xi] 25% (CFB-subcritical)[xii]	35 – 40%[xiii]	44-48%[xiv]	45-49%[xv]
Capital Cost [xvi] (TPC; $/kW) India:	610 (w/o FGD)[iii] 750 (w/ FGD)[iii]			770[iii]	1240[iii]			1290[xvii]	
Worldwide[xviii]:	930-1090 (w/o FGD)[xix] 1080 – 1280 (w/FGD)[xx]	1090-1290[xxi]	960-1300[viii]	1070-1340[ix]	1400-1500[x]	1860[xi] 2370-2410[xii]	1200-1610[xiii]	1250-1270[xiv]	1320-1380[xv]
Emissions Controls									
Particulate Matter	ESP required; Bag filters with high ash is difficult			ESP required; Multiple cyclones and bag filters may be needed.		ESP required; Use of bag filters with high ash is difficult. Multiple cyclones for Oxy-CFBC	Gas cleanup – ceramic filters. Reliability is an issue.	Gas cleanup – ceramic filters. Multiple cyclones may be needed	Gas cleanup – ceramic filters. Reliability is an issue.
Fly ash / Solid waste	Depends on coal quality	Depends on coal quality; less fly ash than subcritical PC. Slagging is an option		Depends on coal quality; Gypsum byproduct		Depends on coal quality; Slagging is an option. Gypsum byproduct for Oxy-CFBC.	Less solid waste; slag byproduct	Less solid waste; gypsum byproduct	
Sulfur dioxide	FGD required, as regulations tighten for SO_x emissions			Limestone injection		FGD required, as regulations tighten for SO_x emissions. Limestone injection for CFBC	H_2S production – MDEA/Claus/SCOT process or sulfuric acid removal plant.	Limestone injection	

	Subcritical PC	**Supercritical PC (SC-PC)**	**Advanced / Ultra supercritical PC (USC-PC)**	**Circulating FBC (CFBC)**	**Pressurized FBC (PFBC)**	**Oxyfuel PC/CFBC**	**IGCC -- Entrained-flow**	**IGCC -- Fluidized-bed**	**IGCC -- Moving/Fixed Bed**
Nitrogen oxides	LNB and SCR as needed			Low NO_x production	Very low NO_x production; LNB on gas turbine	Very low NO_x production	Very low NO_x production. LNB for gas turbine.		Low NO_x production. LNB for gas turbine
Mercury Removal[xxii]	With ESP and bag filters, 60-70% removal. ESP alone not effective. Activated carbon injection if needed.			With bag filters 70% removal. Activated carbon injection if needed.		With ESP and bag filters, 60-70% removal. ESP alone not effective. Activated carbon injection if needed.	Removal by particle filters. Carbon bed filters if needed.		
Ease of Carbon capture[xxiii]	MEA scrubbers – limited by SO_x/NO_x content in flue gas. Can be very expensive. Retrofitting to Oxy-fuel combustion is possible, but not attractive.			MEA scrubber – less problems with SO_x contamination. Can be very expensive. Retrofitting to Oxy-fuel combustion is possible, but not attractive.	Similar to CFBC. With topping combustor, additional capture using CO_2 shift reactor might be needed.	Direct flue-gas sequestration is possible. Less expensive, if flue gas purification is not required.	CO_2 shift reactor and MDEA or Selexol gas purification and capture. Incremental cost of capture may be less than MEA scrubbing.		

Table 37: Comparisons of various characteristics of power generation technologies.

Notes:

Acronyms:

B&W	Babcock & Wilcox	MDEA	Methyl Diethanolamine
BWE	Burmeister & Wain Energy	Claus	Claus sulfur removal process
LLB	Lurgi Lentjes Babcock	SCOT	Shell Claus Off-gas Treating process – improves Claus process
HTW	High Temperature Winkler	LNB	Low NOx Burner
KRW	Kellogg Rust Westinghouse	SCR	Selective Catalytic Reducer
KBR	Kellogg Brown and Root	MEA	Monoethanolamine
MSW	Municipal Solid Waste	IHI	Ishikawajima Heavy Industries
MBEL	Mitsui-Babcock Energy Ltd.	BGL	British Gas Lurgi
TPS	Termiska Processer AB		

[i] Source: (NETL, 2004b; PowerClean, 2004)
[ii] Based on average net efficiencies of 210 MW and 500 MW units (CEA, 2005f).
[iii] Source: Nexant (2003) analysis using Dadri ROM coal.

[iv] Based on net efficiency of Surat Lignite power plant using CFBC boilers (CEA, 2005f)
[v] Source: (IEA, 1998; Palkes et al., 2004)
[vi] Source: (Palkes et al., 2004)
[vii] Source: (David and Herzog, 2000; EPRI and Parsons, 2000; Palkes et al., 2004)
[viii] Source: (IEA, 1998; EPRI and Parsons, 2000; Dillon et al., 2004; Palkes et al., 2004)
[ix] Source: (Marion et al., 2003; Palkes et al., 2004; Ghosh, 2005); includes both sub-critical and supercritical steam cycles.
[x] Source: (Ghosh, 2005); very rough estimates.
[xi] Source: (Dillon et al., 2004); with capture, cost is assumed to be in given in 2004$.
[xii] Source: (Marion et al., 2003); includes two cases – with CO2 capture and with direct flue gas sequestration.
[xiii] Source: (David and Herzog, 2000; Parsons, 2002; Marion et al., 2003; Ghosh, 2005) (case 9A; only F-Class turbines are considered)
[xiv] Source: NETL KRW case studies (NETL, 2000a).
[xv] Source: NETL BGL case studies (NETL, 2000b).
[xvi] Cost given in 2004 dollars. The cost information from various studies were adjusted to 2004 dollars using the consumer priced index (CPI).
[xvii] Source: (Nexant, 2003)– F class turbine
[xviii] Although these costs are a bit out of date now, they are still useful for estimating relative cost comparisons for different technologies.
[xix] Source: (IEA, 1998; Ghosh, 2005)
[xx] Source: (IEA, 1998; Palkes et al., 2004; Ghosh, 2005)
[xxi] Source: (IEA, 1998; David and Herzog, 2000; EPRI and Parsons, 2000; Parsons, 2002; Palkes et al., 2004; Ghosh, 2005)
[xxii] Highly dependent on input coal quality. Source: (PowerClean, 2004; Winfield et al., 2004)
[xxiii] Source:(Marion et al., 2003; PowerClean, 2004)

7.2 Technology Rating Scheme

Generally, analysts tend to assess technologies by comparing the levelized cost of generation from power plants with different technologies (for example, see Ghosh (2005)), and studying its sensitivity to various factors. While a levelized cost analysis is useful, it focuses only on economic aspects. While the economics are obviously critical, an analysis focused only on this aspect may not adequately reflect the various attributes of the technology that help meet the various challenges and constraints in the power sector.

Thus, instead of a pure economic or technical analysis, our initial approach involves scoring various technologies along key dimensions that relate to the challenges and constraints of the sector. An overall rating for a technology can be obtained by combining the ratings of different attributes into a single number – this greatly facilitates a comparative analysis across technologies that have a number of different attributes. We rate and rank technologies in the present circumstance, as well as in an assumed future scenario. Such an analysis can help point the way towards possible technology and investment decisions for both near- and mid-term futures. It is also important to note that this approach is only a first-step analysis, and further analysis based on consistent engineering analysis of the different technologies in the Indian context is required.

7.2.1 Technology assumptions

In order to provide a common basis for comparisons, all of the technologies are assumed to be used in power plants built in Northern India, using hard Indian coal as feedstock. The Indian coal is assumed to have properties similar to that currently used in Indian plants (see Table 20).

More specifically, for each technology, our assumptions are as follows:

- <u>Sub-critical pulverized coal (PC) without FGD</u>: This is the reference technology for Indian power plants.
- <u>Supercritical pulverized coal (SC-PC)</u>: This technology is similar to the Sipat power plant with moderate increase in steam parameters to supercritical conditions. It is assumed that the technology includes flue gas cleanup technologies, including FGD, low-NOx burners, and SCR (if needed).
- <u>Ultra-supercritical pulverized coal (USC-PC)</u>: The technology is similar to the advanced power plants in Europe and Japan with the latest emission reduction technologies. It is expected that this technology will at least be demonstrated in Indian conditions in the near-to-mid term future.
- <u>Circulating Fluidized-bed Combustion (CFBC)</u>: The technology is similar to existing Kutch lignite power plant, although it is used with hard high-ash Indian coals. The steam cycle is assumed to be subcritical in the present scenario and supercritical in the future scenario.
- <u>Pressurized Fluidized-bed Combustion (PFBC)</u>: The technology is similar to the demonstration plants in Europe and the United States. In the future, the technology is assumed to include a topping combustor for increasing its efficiency.
- <u>Oxyfuel PC/CFBC</u>: Oxygen-blown combustion can be applied to supercritical PC and CFBC systems. It is competitive only when carbon capture is required. For the future, it

is assumed oxygen production is still based on cryogenic techniques, albeit with improved efficiencies.

- IGCC Entrained: Standard IGCC technology with entrained-flow gasifier using commercial gasifiers such as Shell, Texaco, etc. The technology in the future is expected to have better gas cleanup systems with higher efficiency.
- IGCC Fluidized: IGCC technology with fluidized-bed gasifiers such as those developed by BHEL or U-GAS. The technology is expected to have better gas cleanup systems with higher efficiency in the future.
- IGCC Moving: IGCC technology with moving-bed gasifiers such as Lurgi or BGL. Similar to IGCC fluidized-bed, the technology is expected to have better gas cleanup systems in the future.

7.2.2 Assessment attributes

The above chosen technologies are scored on the following attributes that are important for meeting the challenges and constraints for the Indian energy sector:

- *Ability to use domestic coal:* Technologies that are able to effectively use domestic Indian coals enhance the energy security of the country, as the country would not have to take on the risks of foreign imports. The key constraint, of course, to using such coals is their high ash-content and low calorific value. For simplicity, domestic coal refers only to hard black coal, rather than lignite. However, we note that all of the technologies can be operated using a diverse set of feedstock, such as domestic and imported coal (of varying quality), low-calorie fuels like biomass, MSW, and other unconventional alternatives like pet coke or heavy oils . Hence, fuel flexibility is not considered as a separate attribute.

- *Maturity of Technology:* In order to meet India's immediate developmental challenge, technologies must be mature enough to be deployed within the next five years. Hence, technologies that can be commercially available in the short-term are favored over technologies that still in the early-development or pre-commercial phase. Technology maturity is assumed to be in the global context, since the current Indian environment is open to global technologies and technology providers. However, it must be noted that global maturity does not necessarily imply that these technologies are similarly mature in Indian conditions.

- *Indigenous technical capacity:* The ability for Indian manufacturers to develop, adapt, and manufacture technologies is relevant to both energy security as well as the country's broader development aspirations. Self-reliance in technical capacity ensures that technologies can be operated and maintained without problems associated with availability of spares, need for outside technical expertise in solving problems, etc. Enhanced technical capabilities in this sector also contribute to the strengthening of the broader industrial base of the country.

- *Low Capital Cost:* The capital cost of technologies is perhaps the most important criterion for the Indian power sector. Low cost of building new power plants is crucial for meeting the challenge of India's developmental goals, given the limited financial resources available for new generation capacity. Cost of electricity (COE) is another criterion used often to judge technologies, but it is not included in this analysis because of the unavailability of complete and proper COE studies for all our chosen technologies.

- *Efficiency:* Technologies that convert coal into electricity with high efficiency address several challenges including enhancing energy security, reducing local environmental impacts, and limiting carbon emissions. This is another important criterion, as high efficiency can also reduces operational costs, leading to better financial returns in the long run. (We have separated capital cost and efficiency to allow these attributes to be scored independently and allocated different weights if needed).

- *Low environmental impact:* Impact of coal power plants on local environment is increasingly becoming a key issue for many stakeholders. Although a technology's environmental impact generally correlates with its efficiency, the environment attribute is considered separately since the environmental impact of technologies depend on just on efficiency, but on the characteristics of the combustion/gasification process and on the addition of pollution control technologies.

- *Carbon capture potential:* Although capturing CO_2 is not an attribute of consideration in India's power sector today, the ability of technologies to economically capture CO_2 is expected to become a very important issue in the future, as impacts of global climate change become more apparent. Given that the lifetime of a power plant can be 40-50 years, carbon capture is very likely to be an important future issue. Hence, we must consider a technology's potential for economic carbon capture, as it will (and should) play a role in future technology choice and investment decisions.

Note that the attributes listed above are not completely independent of each other; for example, as a technology matures, its costs are lowered through technological learning and economies of scale, and high-efficiency technologies will have better environmental performance. Despite such interdependence, the chosen attributes do correspond to different aspects of technologies and relate differently to the challenges and constraints, as summarized in Table 38.

Attribute	Related national/energy challenges
Ability to use domestic coal	Energy security
Maturity of technology	Development
Indigenous technical capacity (R&D/Adaptation/Manufacturing)	Energy security
Low Capital Cost	Development
Efficiency	Energy security Local environment Global environment
Low environmental impact	Local environment
Carbon capture potential	Global environment

Table 38: Attributes chosen for rating technologies and their corresponding challenges and constraints**.**

7.2.3 Ratings and analysis

Based on the attributes listed above, the chosen technologies are rated on an ordinal scale of 1 to 10, with a rating of 10 assigned for the technology that best meets a given attribute, a rating of 1 for the lowest performance on an attribute, and an intermediate rating for the others depending on their performance. The ratings were assigned based on the technology assessment in section 7, and they are necessarily subjective. Although other analysts might assign slightly different ratings to the technologies, we expect that the overall relative ratings will generally be similar. Furthermore, the intention is to assess relative performance, rather than absolute, so these ratings must be considered only a guide towards better decision making, and not taken literally.[426] While it is possible to objectively quantify the ratings on efficiency, capital cost, and environmental performance, it is not possible to do so easily for attributes such as ability to use domestic coal, maturity of technology, and indigenous technology capability. Therefore, for the latter attributes, we need to use an ordinal scale, whereas it is possible to use a ratio scale for the former attributes. However, as noted earlier in section 7.1, we do not have consistent comparative techno-economic studies for all the different technologies in the Indian context. Hence, for a first-step analysis, we compare all of the attributes on an ordinal scale from 1 to 10.

The technologies were rated under current status and performance, as well as in a future scenario (assumed to be about 10 years from now), wherein we make some assumptions about the trajectory of technology development (see below). The analysis of the current state is useful in understanding what technology choices should be made immediately, given that there is an urgent need for enhancing power generation in the country. The analysis of the future is necessary to understand how the rapidly changing global technology landscape might affect decision-making in the Indian context over the next decade or so. The ratings of technologies in the present and in a future scenario are shown in Table 39 and described in detail in Table 40. Note that in the future scenario, technologies are rated against an additional attribute for carbon capture potential. Although carbon capture is not relevant in present circumstances, we expect that it will play an important role in future technology decisions. Our rationale for leaving it out in the present scenario is that carbon capture in currently available commercial technologies would be too expensive, while reducing efficiency significantly. Furthermore, carbon-capture technologies that are in development or demonstration phase are still evolving and it is premature to implement them in the next few years. Given India's low GHG emissions and limited financial resources (that also must address other developmental priorities), the focus at this point should be on adding efficient generation rather than complicating the issue with carbon constraints. However, as carbon mitigation technologies become more advanced over the next decade, technology options need to be reanalyzed.

We assume that future technologies will improve as per their cost and performance trajectories that were discussed earlier (except for subcritical PC, which is our reference, completely mature, technology). For PC technologies, we assume that plants with supercritical steam parameters have become widespread in India, with ultra-supercritical PC technology being demonstrated in

[426] There will be significant uncertainty and therefore variations in perspectives regarding various aspects of deployment of new and emerging technologies in India. While many analysts and stakeholders simply assume that new technologies can indeed be successfully deployed for power generation in India, the technical risk of using a new technology will be reduced only after a successful demonstration or commercial use under Indian conditions. Currently, there are only two commercialized technologies in India.

Indian conditions. The CFBC technology is assumed to have supercritical steam conditions, and the PFBC technology has a topping combustor to increase efficiency. The technology ratings in the future scenario are highly contingent on assumed technology development pattern, and it is, therefore, malleable. Actual technology investments over the next decade (both in India and globally) will determine technology evolution and its applicability to India.

The overall ratings of the technologies, shown in Table 39, itself indicate an important structure—combustion and gasification technologies rate significantly better for certain attributes and significantly worse in others. This aspect is indicated by shading the high and low rankings differently (higher technology ratings (8, 9, 10) are shaded lightly, the lower technology ratings (1, 2, 3) are shaded darkly and the rest (4, 5, 6, 7) are not shaded; see Table 39). Combustion technologies fare really well for the ability to use domestic coals, maturity of technology, indigenous technological capacity and low capital cost, and really poorly for efficiency, low environmental impact and carbon capture. In contrast, gasification technologies have the exact opposite ratings for the same attributes. The overall better rankings for technologies in the future scenario (i.e., there are more high ratings than low ratings in the future) is a consequence of our assumption that technologies generally get better in the future, as investment in the present pays off.

Attribute	Subcritical PC - no FGD	SC-PC	USC-PC	CFBC (subcritical)	PFBC	Oxyfuel PC/CFBC	IGCC Entrained	IGCC Fluidized	IGCC Moving
Ability to use domestic coal	10	8	5	10	10	8	1	7	7
Maturity of technology	10	9	7	10	2	1	5	2	2
Indigenous Technical Capability	10	8	3	10	1	3	1	5	4
Low capital cost	10	7	3	9	3	1	3	2	2
Efficiency	1	5	10	1	6	3	9	8	8
Low environmental impact	1	4	7	3	5	6	10	10	10
Arithmetic mean	**7.0**	**6.8**	**5.8**	**7.2**	**4.5**	**3.7**	**4.8**	**5.7**	**5.5**
Rank (arthimetic)	2	3	4	1	8	9	7	5	6
Geometric mean	**4.6**	**6.6**	**5.3**	**5.5**	**3.5**	**2.7**	**3.3**	**4.7**	**4.6**
Rank (geometric)	5	1	3	2	8	9	7	4	6

Attribute	Subcritical PC- no FGD	SC-PC	USC-PC	CFBC (supercritical)	APFBC	Oxyfuel PC/CFBC	IGCC Entrained	IGCC Fluidized	IGCC Moving
Ability to use domestic coal	10	10	6	10	10	10	1	7	7
Maturity of technology	10	10	9	10	1	3	8	4	4
Indigenous Technical Capability	10	9	5	9	1	4	5	7	6
Low capital cost	10	8	6	8	1	4	6	4	4
Efficiency	1	7	9	6	8	4	10	9	9
Low environmental impact	1	4	8	5	7	6	10	10	10
Carbon capture potential	2	4	7	5	1	10	9	9	9
Arithmetic mean	**6.3**	**7.4**	**7.1**	**7.6**	**4.1**	**5.9**	**7.0**	**7.1**	**7.0**
Rank (arthimetic)	7	2	3	1	9	8	5	3	5
Geometric mean	**4.1**	**7.0**	**7.0**	**7.3**	**2.5**	**5.3**	**5.8**	**6.7**	**6.6**
Rank (geometric)	8	2	2	1	9	7	6	4	5

Table 39: Technology Ratings in the present context (top) and a future scenario (bottom). The future is assumed to be about 10 years from now. Low ratings (1, 2, 3) are shaded darkly, whereas high ratings (8, 9, 10) are lightly. See Table 40 for details on technology ratings and their evolution from the present to a future scenario.

Attribute	Comment on Technology Rating
Ability to use domestic coal	While all technologies can theoretically utilize Indian coals, sub-critical pulverized coal and fluidized-bed combustion are proven technologies that are currently utilizing high-ash Indian coals – deserving the highest ratings. Of the technologies considered, IGCC based on entrained-flow gasification is currently least able to use domestic coal – resulting in its low ranking. IGCC based on fluidized-bed and moving-bed combustion/gasification can use domestic coal more readily, but the high ash content might cause problems with the required gas clean up. More advanced pulverized coal technologies might also be initially limited in their ability to use high-ash-content coals. However, in the future, it is expected that all these technologies will be better able to use Indian coals with increased operational experience, technological refinements, and greater use of washed coal to limit ash content. However, in a relative rating scheme, domestic coals might still be least amenable for entrained flow gasifiers.
Maturity of Technology	Presently, sub-critical pulverized coal and fluidized-bed combustion technologies are most mature. Oxyfuel technology is the least mature, with PFBC technology being slightly better as there have been some demonstration plants. Supercritical and ultra-supercritical PC technologies are also mature, albeit with marginally lower ratings in comparison to sub-critical PC. Although IGCC based on entrained-flow gasifiers is a well-established technology, its maturity is not quite as high as the PC technologies. IGCC based on fluidized-bed and moving-bed gasification get marginally lower ratings than IGCC-entrained-flow, as there is much less technology development for these gasifiers. It is expected that in about 10 years, most of the technologies considered here will be closer to commercialization, with the PFBC being the least mature because of current limited investment in its development.
Indigenous technical capacity	Indian technical capacity is most advanced for developing and manufacturing subcritical PC and CFBC technologies, with capacity for supercritical PC slightly limited by lack of materials development. Technical capacity is the lowest for PFBC and IGCC-entrained flow, with capacity for oxyfuel technology being slightly better as the basic combustion technology is very similar to standard PC/CFBC. Capacity does exist for adapting and manufacturing ultra-supercritical PC and IGCC with entrained-flow gasifiers, although most of the designs and materials will have to be imported. Some indigenous R&D and manufacturing capacity exists for fluidized-bed gasification and moving-bed gasification, although the operation of a large-scale IGCC plant based on these technologies is yet to be demonstrated. In the future, it is expected that indigenous technical capacity for R&D, adaptation, and manufacturing advanced technologies will be improved significantly (contingent on attention being paid to this issue), but the relative ratings might still remain similar to the present scenario.
Low capital cost	From a pure economic perspective, where social and environmental costs are externalized, advanced technologies do not compete well with the standard sub-critical PC and CFBC technologies. CFBC is ranked slightly lower than PC, as it has slightly higher capital cost. Advanced PC technologies are also expensive, although not as much as IGCC or PFBC technologies. IGCC-entrained flow is rated marginally higher than IGCC with fluidized bed or moving bed gasifiers, and Oxyfuel technology is rated the lowest, as it is currently the most expensive, especially when used with subcritical technologies. However, with increasing coal

	price and demand for clean, high efficiency power plants, advanced technologies might get support for early deployment, and operational experience from such deployment will lower future costs. In the future, it is likely that APFBC costs will continue to be high (again because of limited investments in the technology), with IGCC technologies reducing their costs the most. Still, we expect that advanced PC technologies will continue to have lower costs than other non-PC advanced technologies. Cost of oxyfuel technologies might also improve significantly with investment in its development.
Efficiency	Ultra-supercritical PC currently would have the highest efficiencies, with IGCC with entrained-flow gasifier being rated slightly below. IGCC with fluidized-bed and moving-bed gasifiers are assumed to be slightly less efficient than IGCC with entrained-flow gasifiers. Subcritical PC and CFBC are the least efficient. The efficiency of PFBC is relatively high; perhaps even higher supercritical PC for domestic coals. Oxyfuel technologies will suffer from efficiency penalties, with high auxiliary consumption for producing oxygen. In the future, efficiencies of all advanced technologies are expected to rise, with gasification technologies getting greater improvements than combustion technologies. APFBC is expected to have better efficiency than PFBC technology, with the addition of a topping combustor.
Low environmental impact	IGCC technologies have the least, and sub-critical PC the highest, impact on local environment. Since advanced PC technologies utilize FGD and SCR, they have lower emissions than the standard PC technology, although they still rate lower than IGCC technologies. The environmental impact of Oxyfuel technology is expected to be similar to that of the advanced PC technologies, although with lower NO_x production. Fluidized-bed combustion technologies are better for the environment, as they have lower SO_x emissions. In the future, the environmental performance is generally expected to be the same as in the present, although the increase of efficiency for CFBC and APFBC leads to higher ratings, and ultra-supercritical PC is expected to be closer to IGCC performance.
Carbon capture potential	Although theoretically all technologies allow for carbon capture, the efficiency and cost impacts of capturing CO_2 can be prohibitively high for some technologies. Generally, the economic potential for capture increases with PC technologies as their efficiency gets better. IGCC and Oxyfuel combustion plants are expected to be most suitable suited for economical carbon capture, although Oxyfuel combustion is given the highest rating as its flue gas could be directly sequestered without much cleaning, whereas IGCC requires a CO_2-shift reactor and a capture plant. PC technologies with relatively high contaminants in flue gas are less amenable for carbon capture, and so they have low ratings. CFBC gets a marginally better rating than supercritical PC because of the lowered SOx content in its flue gas. APFBC gets the lowest rating, as it might require both a shift reactor and a MEA scrubber to significantly reduce CO_2 emissions. It is expected that capture technologies themselves will be improved significantly over the next 10-15 years as greater attention is devoted to this topic worldwide.

Table 40: Comments on rating of technologies (see Table 39).

Although the ratings tables by themselves provide information for decision-making regarding technology choices, the ratings on the multiple attributes can also converted into a single index for each of the technologies, despite the fact the ratings are all on ordinal scales. The single index is calculated using two different methods: the arithmetic mean and the geometric mean. The arithmetic mean provides information about the overall average of the ratings on the various attributes, whereas the geometric mean is sensitive to spread of the ratings (being derived from their product). So, for example, final rating for subcritical PC in the present scenario gives a higher value for the arithmetic mean because it has the highest score of 10 in four of seven dimensions, but a lower one for geometric mean because it also has the lowest score in two categories. On the other hand, the geometric mean of supercritical PC in the present scenario is the highest, despite the fact that it does not have a single score of 10, because it rates reasonably against all of the criteria. Although using standard deviation of the ratings is another option, it is not as useful as geometric mean because standard deviation only gives information about variations relative to the arithmetic average, whereas we are more interested in determining variations relative to the endpoints on the ordinal scale. Hence, ratings close to the lower end of the scale would be given greater weight in the geometric mean.

In calculating the arithmetic and geometric averages, we give equal weight to each attribute, rather than emphasizing a particular attribute over others. We recognize that this is a particular choice that we are making, and that different stakeholders may value certain attributes over others. Indeed, a survey of representative stakeholders can be used to assess these value judgments, which can then be used to add weights to the attributes. In order to assess whether adding weights to the rankings will change the technology assessment, we have carried out a sensitivity analysis by taking averages (both arithmetic and geometric) after doubling the weight of each attribute relative to others (see discussion below and Appendix A).

The ratings of the technologies and their relative rankings based on the two different indices are shown in Figure 46.

The overall scoring of the technologies indicate that supercritical PC with FGD and CFBC rank as the best overall technology options in the present circumstances; supercritical PC because of its efficiency, maturity, and relatively low cost and CFBC because of its fuel flexibility and reduction in SOx and NOx emissions. Although subcritical PC has a better score in the arithmetic mean, it fares poorly for the geometric mean – indicating that it is not the best overall technology (especially as it rates poorly for efficiency and environmental impacts). IGCC technologies, as well as the more advanced technologies such as PFBC and oxyfuel combustion, are currently not the best options because of their low maturity and relatively high costs, although they rate high for efficiency and low environmental impact. Our sensitivity analysis indicates that the above assessment holds even with any particular attribute receiving double weighting, except that sub-critical PC fares poorly if efficiency and environmental impacts are weighted higher than others.

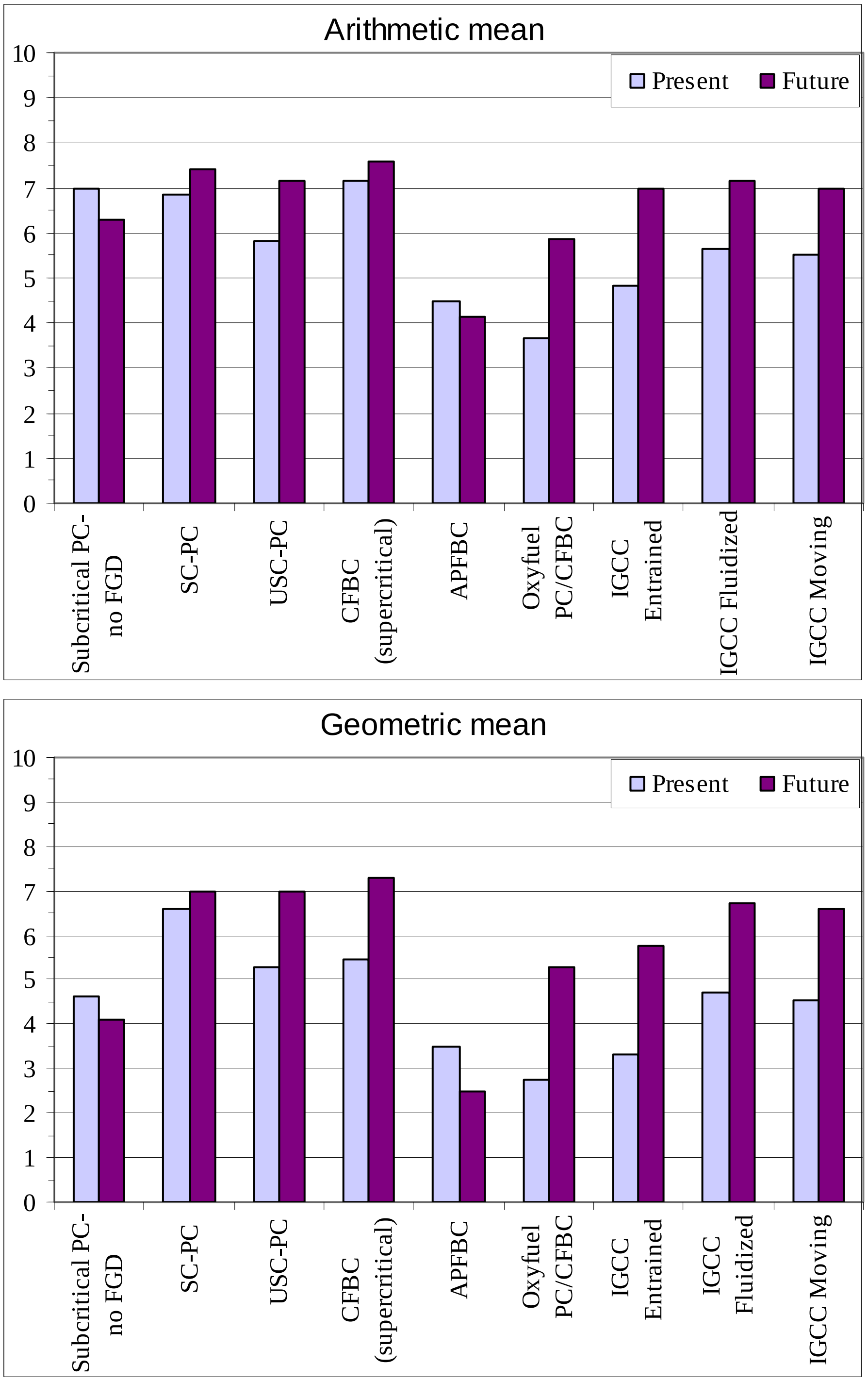

Figure 46: Calculations of arithmetic and geometric means of the technology ratings.

.

Our analysis under the mid-term future scenario indicates that the current PC and CFBC technologies using subcritical steam conditions and the advanced-PFBC technology are not suitable for meeting the future challenge of high efficiency and carbon mitigation. The best technologies for India in the mid-term future seem to be CFBC technologies, supercritical PC and ultra-supercritical PC. IGCC fluidized-bed and moving-bed technologies also rank high, but lower than the more efficient combustion technologies. In addition, oxyfuel and IGCC entrained-flow technologies will likely become important options as they can effectively meet the carbon capture challenge. As in the present scenario, the sensitivity analysis does not significantly alter our assessments. The sensitivity analysis indicates that the IGCC with fluidized-bed ranks higher when low environmental impact and carbon capture aspects are weighed higher than the rest. The IGCC fluidized-bed and moving-bed technologies generally rank better than IGCC entrained flow in all circumstances.

The above technology assessment using the rating scheme can be compared with other technology assessments in the Indian context – Ghosh (2005) and Nexant (2003) – although both of these studies make assessments primarily in the present circumstances. Our assessment that supercritical PC technology with FGD is currently the best technology option for India is supported by Ghosh's (2005) levelized cost analysis of technologies, which indicates that the higher efficiency of supercritical PC technology outweighs the lower capital and O&M costs of the subcritical plants, even with low coal prices. The study also notes that the cost of generation using supercritical technology is competitive with NGCC plants when gas prices are above $4/GJ (Ghosh, 2005). Nexant (2003) uses an assessment matrix, somewhat similar to our analysis but using a smaller set of technologies and with the matrix being heavily weighted in favor of cost (45%) and environmental performance (35%).[427] This analysis indicated that subcritical PC is currently the best technology suited for Indian coals, with supercritical PC with FGD ranked the next highest. The study concludes that current IGCC technology, based on U-GAS gasifiers and F-class turbines, does not compete well with PC and CFBC technologies when used with Indian coals; although a future IGCC plant with a H-class turbine might be competitive in the Indian context (Nexant, 2003). The Nexant analysis is consistent with our analysis that combustion technologies generally fare much better in the Indian context than gasification technologies.

Finally, as noted earlier, the above analysis is only a first step towards a better technology assessment for India that incorporates key challenges and constraints in the Indian coal power sector. There are several ways in which this analysis can be further refined. For example, the performance of technologies on various attributes can be rated by a number of different experts and stakeholders using surveys. We can also develop a better understanding of the utility of various attributes in the views of a range of stakeholders (or even refine the list of relevant attributes). In fact, surveys of stakeholders' utilities can form the basis of a multi-attribute utility analysis, which allows for a robust assessment of technological options (in comparison to our simple averaging and equal weighting schemes). Another possibility is to disaggregate into finer details the broad attributes we used in our analysis: for instance, indigenous technical capacity can be further broken down into R&D capacity, adaptation capacity, and manufacturing capacity. Another method of improving the current analysis is to break-down the technologies into various components and assess those smaller components rather than the technology as a whole. In many cases, the various technologies discussed above rely on an underlying set of components or sub-systems such as control systems, coal handling and processing, emissions control, etc. An analysis of these components might be useful for determining what might constitute specific barriers or challenges in the Indian context, which in turn can help fashion more targeted technology strategies.

[427] Environmental performance includes efficiency.

8 Towards a Clean-Coal Technology Roadmap

Technology assessments and analyses of the kind carried out in chapters 6 and 7 can serve as the basis for devising a roadmap for coal-sector power generation technologies. In this section, we present such an illustrative technology roadmap that highlights technology choices, strategies, timelines, and specific RD^3 activities. We then detail the key policy elements that will allow for the suitable implementation of this roadmap. We also highlight a set of enabling conditions and activities that are necessary for making these policies effective—these conditions will also generally add to the institutional and technological capacity for meeting the power sector's future challenges. Finally, we suggest specific processes and institutional structures that would help the development of a national clean-coal technology roadmap for India.

8.1 Illustrative Technology Roadmap[428]

An illustrative technology roadmap for the country is presented below (Figure 47 and Table 41), based on the technology assessment and analysis presented earlier. Note that this roadmap is meant to describe one possible set of options, based on our preliminary and necessarily limited analysis, and should not be treated as authoritative or unique. As we have highlighted earlier in section 5.2, the development of a national roadmap must emerge from a detailed and systematic process that includes input and perspectives from a range of stakeholders. Table 41 also shows some of the key actors and international linkages for each technology innovation process. This list of actors is preliminary and not inclusive, and a more detailed account of national and international actors needs to be defined through a national roadmapping process.

There are significant technical uncertainties regarding certain technologies, such as USC-PC, IGCC, PFBC, oxyfuel combustion, and carbon capture and storage. These uncertainties are indicated by the question marks in Figure 47. There are at least two types of uncertainties: a) uncertainties about how the global technological development is likely to take place in the coming years, and b) the uncertainty regarding the applicability of technologies in the Indian conditions. Hence, the timelines shown in Figure 47 would change as technological uncertainties are reduced in time.

Given the technological uncertainties, our analysis suggests that India should not make rigid technology choices for the long term, but rather keep its technology options open. Combustion technologies continue to improve in their efficiency and the possibility of oxygen-fueled combustion increases the potential of combustion-based plants being able to capture carbon efficiently and cheaply. On the other hand, it is expected that gasification technologies will also continue to make progress in terms of, both, technical improvements and cost reductions. It seems likely that IGCC will have a significant market share in the industrialized-country electricity markets over the next several decades, as the need for carbon capture in power plants become more of a reality. However, we cannot at this point project whether combustion or gasification technologies will dominate the global power sector in the next few decades.

[428] In December 2006, we learned about the research activities of Dr. Ajit Kumar Kolar of IIT-Madras, who has independently developed a version of the roadmap presented here. See: (Kolar, 2006)

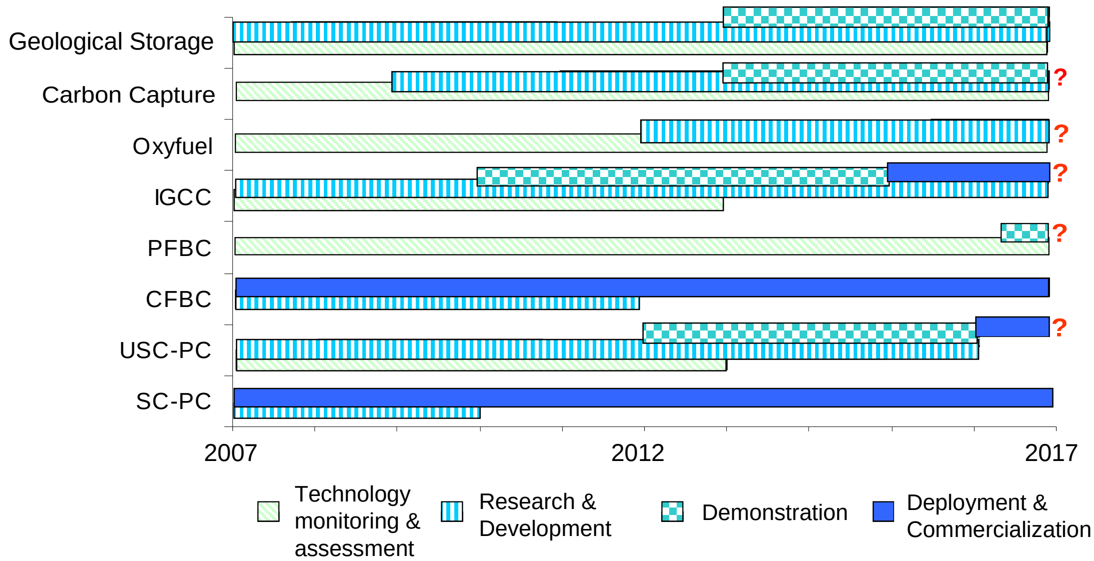

Figure 47: Illustrative technology innovation roadmap. Basic and applied research, as well as technology development is included in the 'research and development' category. The question marks indicate the uncertainty associated with future technological progress with certain technologies (see text).

Therefore, as shown in Figure 47 and Table 41, we suggest that the country embark, in the near-term, on a major commercial deployment of supercritical PC and CFBC power plants, as also recommended by others (see for example, (Abbi, 2003; CEA, 2003; Ghosh, 2005)) – these technologies are already available and well-tested and their deployment will lead to large efficiency gains. At the same time, there must be careful planning for the future on two simultaneous tracks. The first involves paying particular attention to two sets of near-commercial technologies – USC-PC and IGCC – and embarking on a basic and applied research and development program to ensure that these technologies can deployed if they emerge, based on global and domestic technology progress in the next decade or so, as suitable options for the Indian power sector. This is a "*research-and-wait*" option. At the same time, it is also important to establish a program to review and monitor global developments on emerging technologies, such as oxyfuel and PFBC, to assess their potential relevance for India's power sector. These technologies are not relevant for India in the short-term, but could prove to be important in the long term. Hence, this is a "*watch-and-wait*" option.

Carbon capture would also come primarily under the *watch-and-wait* approach at this point, as India would likely rely on technology developments and cost-reductions based on technology innovation in industrialized countries—therefore, it will be critical to pay close attention to worldwide developments in carbon capture technologies. In addition, some research on multi-pollutant control and carbon capture from 'dirty' flue gases from Indian power plants can also be initiated. Depending on the rate of global technological progress, pilot scale demonstration of carbon capture could also be considered in the future. In the meantime, one might also want to consider leaving additional space during construction for future retrofitting of carbon capture equipment. In addition, it is important to do engineering based studies on carbon capture options for IGCC based on fluidized bed gasifiers, as there may be similar issues regarding retrofitting of these systems, as was discussed for entrained flow gasifiers in section 6.6.1.1. More generally, a detailed techno-economic analysis is required to determine the best strategy for making power plants 'capture-ready' in the Indian context.

Technology	Technology Monitoring and Assessment	Research & Development	Demonstration	Deployment Early Deployment/Commercialization		Key Actors	International Aspects
Subcritical PC	Assess options for retrofitting of pollution-control technologies.	Efficiency improvements, reduction of auxiliary consumption	Demonstrate better SO_x and NO_x control technologies;		Use of better pollution control and efficiency improvement technologies.	NTPC, SEBs, private utilities, BHEL, International manufacturers.	CENPEEP and other programs for training and transfer of know-how.
SC-PC	Monitor worldwide activity, particularly use of biomass mixtures and low quality coals, and assess feasibility for India.	Materials research; computational modeling for adaptation to Indian conditions.	Demonstrate FGD and pollution control technologies	Two under construction; learning is critical.	Rapid deployment; build up of manufacturing capacity; feedback to adaptation research.	**R&D:** BHEL, National Labs; **D&D:** NTPC, SEBs, BHEL, International manufacturers	Commercial linkages
USC-PC	Monitor worldwide activity, particularly use of biomass mixtures and low quality coals. Techno-economic feasibility for domestic and imported coals.	Materials research; computational modeling; adaptation research; advanced coal beneficiation would be useful.	Strategic planning needed.			**R&D:** Academia, National Labs, BHEL, NTPC, Coal industry	R&D collaborations in materials and adaptation research
CFBC	Monitor use of biomass mixtures and use of waste coal and washery rejects.	Adaptation and scale-up for use with waste coal and washery rejects. Constructive utilization of CFBC ash-waste.	Large scale demo for washery rejects	Use with washery middlings and waste coal.	Increase thermal efficiency and PLF; Improve environmental performance.	**R&D:** BHEL, National Labs; SEBs, BHEL, **D&D:** Coal industry, washery operators, Int'l Manufacturers	Commercial linkages
PFBC	Monitor worldwide activity (particularly, Japan), and assess feasibility for India.						
IGCC -- Entrained	Monitor worldwide activity (U.S., Europe, Japan, China, etc.) and assess feasibility for India, particularly polygeneration projects. Explore use of petcoke, imported coal, and tertiary Indian coals.	Advanced air separation technologies; Adaptation research R&D for chemicals production and polygeneration.	Polygeneration demonstration and IGCC with petcoke and imported coals should be considered	Commercial petcoke-based IGCC in consideration.		**R&D:** Academia, national Labs, coal industry, petrochemical Industry	R&D collaborations, particularly on polygeneration. Commercial linkages also possible.

Technology	Technology Monitoring and Assessment	Research & Development	Demonstration	Deployment Early Deployment/Commercialization		Key Actors	International Aspects
IGCC -- Fluidized	Monitor worldwide technology development and assess feasibility for India, building on USAID/Nexant effort. Assessment of BHEL gasifier technology. Use of blended coal and washery rejects needs to be explored.	Adaptation research and R&D for scale up of BHEL and other gasifier technologies; advanced air separation and flue-gas cleanup technologies. R&D for polygeneration should be explored.	BHEL-NTPC planned IGCC demonstration using domestic coal; Polygeneration demonstration should be considered.			**R&D:** NTPC, BHEL, National Labs, Coal industry, Petrochemical industry; **Demo:** NTPC, Petrochemical Industry, BHEL, International manufacturers	RD&D collaboration and commercial linkages
IGCC – Moving / Fixed	Monitor worldwide technology development and assess feasibility for India. Assessment for use with waste coals.	Adaptation research using BHEL and Sasol gasifier technology.	Polygeneration demonstration should be considered, if cost-effective.			**R&D:** NTPC, BHEL, National Labs, Coal industry, Petrochemical industry; **Demo:** NTPC, BHEL, Coal washeries, Int'l manufacturers	RD&D collaboration and commercial linkages
Oxyfuel	Monitor worldwide activity (U.S., Europe, and Australia) and assess feasibility for India, particularly retrofit projects.	Adaptation studies for retrofitting; R&D on advanced air separation technologies	Strategic planning needed, if deemed suitable for India.			**R&D:** NTPC, BHEL, Academic and National Labs	R&D collaborations
Carbon Capture	Monitor worldwide activity (U.S., Europe and assess feasibility for India, particularly retrofit projects.	Adaptation and retrofit studies. Research on multi-pollutant control and carbon capture of 'dirty' flue gases.	Strategic planning needed. Pilot scale demo can be considered, to test technology for Indian coals.			**R&D:** NTPC, BHEL, Academic and National Labs, Petrochemical industry	R&D collaborations
Storage	Monitor worldwide activity (U.S., Europe, Australia, and China) and assess feasibility for India.	Detailed geological reservoir mapping; assessment of storage mechanisms and capacity; adaptation research.	Pilot scale storage and monitoring needs to be strategically planned.	Explore link with CO_2-based EOR.		**R&D:** Academic and National Labs, O&NG industry, Geological Survey of India, NTPC	R&D collaborations, particularly with CSLF.

Table 41: Details of the Illustrative Roadmap (short-term; up to 2015)

In addition, as discussed in section 6.6.4, it is crucial for India to initiate basic exploration research on detailed storage options. Particular attention must be paid to developing a better understanding of geological storage through detailed studies on reservoir mapping and specific site characterizations for large-scale geological storage (of the order of a million tons of CO_2 per year). Although such a program will require significant financial and human resource investment, it will be invaluable in guiding decisions about future technology choices and siting of future plants. Also, early demonstration of storage might involve CO_2-based enhanced oil recovery and industrial plants such as refineries and fertilizer plants that might already produce streams of CO_2 as part of their industrial process. Rather than venting the CO_2 streams to the atmosphere, they can be also used for pilot storage projects.

For any given technology, there may be a number of different possible deployment pathways, which in turn would have different implications for technology strategies. For example, in the case of IGCC, a technology that will likely be deployed in industrialized countries in the near-term, it is important to consider various pathways for its possible deployment in the Indian context:

1. One possibility could be to evaluate the performance of specific IGCC technologies using Indian coals in demonstration plants (an option under active consideration as a joint implementation project between NTPC and BHEL). This approach based on fluidized bed gasifiers gives primacy to the use of Indian coals and to the adaptation of IGCC technologies accordingly.

2. Another option would be to deploy IGCC using imported coal, so as to gain operational experience with IGCC plants based on standard entrained flow gasifiers. This would allow Indian firms to learn from the operation of commercial-scale IGCC power plants, but without having to solve upfront the technical problems associated with the gasification of Indian coals. In fact, given the recent concerns about the limited availability of domestic coal, it might be worthwhile to consider a future scenario with a technology bifurcation where domestic coal is used in combustion technologies, and commercial IGCC plants are run with imported coals.

3. Yet another possibility could be to emphasize the use of less-conventional feedstock, such as pet coke, heavy oils, and biomass in the Indian IGCC development and deployment. This approach could be based on either entrained-flow or fluidized bed gasifiers, depending on the feedstock.

An overarching issue with IGCC is to determine whether the technology should be used purely for power-generation or for polygeneration. Since IGCC involves complex chemical conversion processes rather than just thermal conversion, taking the polygeneration route (i.e. producing high-value products such as FT liquids and chemicals) has the advantage of involving the chemical industry, which has significant experience with complex chemical processes, including gasification.[429]

[429] In fact, the issue of involving a wider range of industrial actors than the traditional power plant manufacturers and operators is relevant even for carbon capture, where once again the expertise of chemical firms, such as those involved in gas separation, may be particularly critical.

Another important issue for future technology development in the Indian coal power sector is the use of different fuel feedstock. Currently, Indian power plants are designed to handle the low calorific value and high ash Indian coals. However, technologies that are designed to be flexible enough to use different kinds of fuels as feedstock might be advantageous.[430] Fuel flexibility can provide greater opportunities for utilizing economically viable fuels in the future. Co-firing with biomass is also another option that can be considered to reduce CO_2 emissions.

Power plants that rely on a single source of fuel, particularly pithead plants near coal mines, must be built only after due consideration for securing fuel supplies for the plant's entire lifetime. Foresight and forethought is necessary, lest power plants become stranded because of reduced fuel supply or high fuel costs. In addition, the use of high-calorie and low-ash-content imported coal extends the range of available technology options. Building power plants at coastal locations that are near to both load centers and port facilities could enhance flexible supply of economic fuels to power plants,[431] albeit environmental controls and enforcement will have to be much tighter for power plants located in the ecologically sensitive coastal regions.

[430] A broad portfolio of fuel options for the coal power sector could include:

Primary fuel:

- Domestic run-of-mine (ROM) coal (Grades D,E,F)
- Domestic washed coal (34% ash content)
- Domestic coal washery middling and waste coal
- Domestic lignite
- Imported coal (high calorific value)
- Imported coal (low calorific value)

Supplementary fuel:

- Petroleum products – Naphtha, Heavy Fuel Oil, High Sulfur Diesel
- Petroleum coke
- Orimulsion
- Natural Gas (Imported and Domestic)
- Regasified Liquefied Natural Gas (Imported)
- Biomass
- Municipal solid waste (MSW)

[431] Such coastal plants are already being planned according the Ministry of Power's ultra-mega power project scheme. See: powermin.nic.in.

8.2 Policy elements for roadmap implementation

Implementation of the illustrative technology roadmap will require a number of interlinked activities. We note that while the illustrative roadmap above is centered on coal-power generation technologies to be deployed in the future, there is a range of "no-regrets" policies that can better prepare the power sector to meet its upcoming challenges, as well as help in implementing a technology roadmap. Five basic elements of such a short-term 'no-regrets' policy are described below:

8.2.1 Improve efficiency of all elements in the existing power system

Improving the efficiency of the existing power system allows for a greater and better delivery of electricity with the existing generation stock. Efficiency increase in the overall power system (generation, transmission & distribution, and end-use) also delivers an important and crucial side benefit in that it is akin to adding generation capacity without actually doing so. Thus, it slows down the addition of generation capacity and buys time to resolve the technical and market uncertainties associated with emerging or new technology options associated with the roadmap. Efficiency improvement also increases the country's energy security, as the power system becomes more robust and well maintained.

8.2.1.1 Generation

The efficiency of existing sub-critical PC power plants have great potential for improvement. As noted in Section 2.4.6, the average net efficiency of the overall sector is 29%, with the 500 MW units being 33% (Chikkatur, 2005).[432] The efficiency of existing power plants can be improved by 1-2 percentage points on average. Efficiency improvement by one percentage point would reduce coal consumption and CO_2 emissions by about 3% (Deo Sharma, 2004). Improving the efficiency of generation in power plants is also a crucial first step for carbon capture. CO_2 capture is economical only when power plants are run as efficiently and cleanly as possible. Furthermore, retrofitting of plants with carbon capture is only economically feasible with high efficiency plants.

Low efficiency is usually blamed on many technical and institutional factors. The use of poor quality coal is particularly problematic as it increases auxiliary consumption, operation and maintenance costs and time, and reduces overall efficiency. Hence, use of better quality coals, including washed coals, would improve efficiency. Changes in management practices and institutional structures might also improve efficiency (Khanna and Zilberman, 1999). The CEA (2005f) has noted that lack of emphasis on efficiency during operations and maintenance of the power plants is one of main reasons for poor performance. Hence, it is important for all power plants to measure efficiencies routinely and carry out energy audits to assess their efficiency levels.

Improving energy efficiency of existing plants will require a two-pronged approach: the use of regulatory frameworks to promote energy-efficiency improvement and the enhancement of technical capability to make such improvements. On the former front, regulators can provide

[432] In comparison, the average efficiency for the top-50-most-efficient U.S. coal-based power plants is 36%, with the fleet average being 32%. See: http://www.powermag.com/plants_top.asp

incentives for efficiency improvement by tightening heat-rate requirements or linking tariffs to heat rates (see, for example, Chikkatur et al. (2007a) for an example of a tariff-based incentives for promoting efficiency improvements in thermal power plants). However, the success of these incentives very much depends on the availability of technical capacity to make such improvements. Some activities in this area have already been initiated by USAID and NTPC with the creation of CenPEEP, which acts as a resource center for acquiring, demonstrating, and disseminating technologies and practices for reducing greenhouse gas emissions from power plants.

Efforts such as CenPEEP must be strengthened and expanded nationally – NTPC could play a particularly key role here, given its experience and capabilities in this area. Current government efforts have been more focused on increasing generation and extending the life of older units (through the renovation, modernization and life-extension programs) rather than specifically improving efficiency. Hence, regulators must focus on more aggressive approaches to improve efficiency of existing power plants, while at the same time a focused program must be initiated to provide technical and financial assistance to utilities for efficiency improvement, especially at the state level (Chikkatur, 2005). Cooperation with organization from industrialized countries (the Department of Energy, various national laboratories, and Electric Power Research Institute (EPRI) in the United States, the International Energy Agency, and the Central Research Institute of Electric Power Industry (CRIEPI) of Japan could play an important part in helping India to further its efficiency improvement programs. Furthermore, it is important to consider refurbishing (or repowering) older units with more-efficient higher capacity units that use cleaner pollution control technologies.

8.2.1.2 <u>Transmission and Distribution</u>

India has made major strides in the expansion and enhancement of its transmission and distribution network – the bulk transmission network (i.e., 132 kV or greater) has increased from 3708 circuit km (ckm) in 1950 to over 265000 ckm.[433] At the same time, there also has been a move towards higher-voltage lines and integration of the regional grids into a national grid. Yet the performance of this transmission and distribution network still leaves much to be desired, with high losses due to (Planning Commission, 2002b):

- long transmission and distribution lines and a high ratio of low-tension to high-tension lines;
- haphazard growth to meet the short-term objective of extension of power supply to new areas, which has led to an inadequate sub-transmission and distribution systems.
- inappropriate size of conductors; and
- improper load management, resulting in overloading of systems.

Estimates of transmission and distribution losses for India routinely suggest that these are higher than those in most other countries. Current losses in the Indian transmission and distribution system is very high and reducing these losses to a more manageable (though still high) 10% will release power equivalent to about 10,000-12,000 MW of capacity (CEA, 2007b). The aggregate technical and commercial losses[434] are higher than T&D losses— although exact data are hard to

---

[433] http://powermin.nic.in/transmission/transmission_overview.htm, accessed April 8, 2007

[434] Commercial loss is generally a euphemism for outright theft of electricity.

come by, it is estimated that AT&C losses vary from 18 to 62%, with the average for the country somewhere in the range of 34 to 40% (Planning Commission, 2002b; CEA, 2007b). Although reducing commercial losses will not reduce demand much (since this power is being used by consumers, even though they are not paying for it), it will increase revenues for the utilities and improve their precarious financial condition, and therefore greatly help increase the availability of financial resources for the power sector.

Many experts have advocated for investments in T&D to be comparable to that in generation (see, for example, Roy (1999)). Yet, despite the recognition of the importance of improving T&D performance, there is still a tendency to take a focus on capacity additions--even in the 10th plan, outlays for T&D were half that of generation (i.e., $19 billion for the former vs. $40 billion for the latter (CEA, 2007b). Existing efforts to upgrade the T&D system by modernizing the existing infrastructure and introducing new technologies must be accelerated through steps such as expanding the high-voltage lines, improving integration among regional grids, and improved monitoring and metering of distribution networks.

8.2.1.3 Demand management and end-use efficiency

Passing of the 2001 Energy Conservation Act and the establishment of the Bureau of Energy Efficiency (BEE) are signs of an increasing recognition of the importance of end-use energy efficiency for the country. This is particularly important since the expected rapid economic growth will lead to acceleration of power demand and of the installation of electricity-based appliance stock, often with fairly long lifetimes (especially for some household goods and industrial equipment). Each kW saved at the end-use side is equivalent to almost 1.8 kW (once auxiliary consumption at the power plant and T&D losses are taken into account). Furthermore, there is also great potential for end-use energy-efficiency gains in the country. For example, it is estimated that the deployment of energy-efficient lighting, more efficient refrigerators in households, and more efficient motors in industry could save as much as 10% of the power generation (Shrestha et al., 1998).

	Domestic	Commercial	Industry	Railways	Agriculture	Others
2005-06 consumption of utility generated-power (%)	24.9	8.4	35.9	2.5	23	5.3
Annual growth (%) (95-96 – 05-06)	8.13	8.49	4.53	5.95	2.02	7.55

Table 42: Consumption and annual average growth of electricity in various sectors.
Source:(Ministry of Finance, 2007).

The industrial and domestic sectors are the two largest consumers of utility-generated power in the country (see Table 42). Consumption in the domestic sector has been growing rapidly, mainly as a result of increasing penetration of energy-consuming appliances such as refrigerators and air-conditioners. As a result, the BEE has been focusing its early efforts on improving end-use efficiency through standards and labels for domestic and commercial appliances, development of codes for energy-efficient buildings, and a focus on industrial end-uses. At the same time, demand-side management measures by utilities, including load shaping, need to be undertaken. While such measures have significant potential, a number of barriers must be overcome for any significant success (Matsuno et al., 1996).

While the Tenth Plan emphasized the need for energy conservation, it did not allocate a specific budget towards these measures. The Working Group for the 11th Plan has suggested an outlay of about \$1.4 billion for energy conservation measures, but this is minuscule in relation to the budget for other elements of the power sector and must be enhanced.

8.2.2 Near-term deployment of higher-efficiency combustion technologies

The technology assessment in chapter 6 indicates that supercritical pulverized coal (SCPC) technology is well suited for the Indian coal power sector in the near term. SCPC technologies, including flue gas desulfurizers, would be at least 5% more efficient than current 500 MW subcritical units and the use of washed coal would increase the efficiency by another 1%; in terms of capital cost, SCPC is only about 7% more than sub-critical PC (Nexant, 2003). Furthermore, SCPC is a commercial technology with many worldwide manufacturers—hence, a key focus should be on adapting and deploying this technology in India.

The Central Electricity Authority has already deemed in 2003 that supercritical technologies are suitable for India and they have recommended rapid deployment of 8-10 new SCPC units. However, only two SCPC plants (with six units) are currently under construction, and a total of 12 SCPC units are currently planned in the 11th Plan (accounting for about 17% of capacity addition). Ten out of the twelve SCPC units are planned under Central ownership, with the one unit each in the State and Private sectors (CEA, 2007b). Thus, there appears to be minimal interest in the state and private sectors in SCPC technology, as they continue to rely on standard sub-critical PC technology. While it is understandable that the Central agencies, particularly NTPC, would take the lead in deploying SCPC, the state and private generating companies must be involved as observers in the Central projects to encourage them to take up SCPC on their own. The CEA and the Power ministry must also promote the uptake of SCPC in the state and private sectors through various incentives. The Power Ministry has already begun some efforts in this regard through its ultra-mega power plant policy, which intends to support several 4 GW projects using SCPC technology. At the same time, innovative efficiency-enhancing incentives could be incorporated into the regulatory framework to promote more efficient plants. Furthermore, it is only through increased experience with this new technology that concerns regarding its reliability, performance, and operating costs will be resolved.

Finally, it is essential for India to develop its own indigenous manufacturing and design capacity for SCPC technology. So far, BHEL has been on the sidelines for the two NTPC projects (Sipat and Barh). BHEL already has licensing and technology-transfer agreements with Alstom for SCPC, and it must now be supported (at least in the initial phases) to begin the adaptation, manufacturing, and installing of indigenous SCPC units in India. One option would be to support a joint NPTC-BHEL SCPC project, similar to the 100 MW IGCC demonstration project.

8.2.3 Long-term approach for emerging technologies

The menu of technological options will continue to evolve as industrialized countries invest in their own programs of research, development, demonstration, and deployment. It is important for India to study and learn from these activities, and to leverage global innovation to its benefit. Technological advances and greater operational experience through these programs will lead to a better understanding of the technical and cost trajectories as well as the feasibility for large-scale deployment of new technologies. Hence, it is important for India to a) monitor evolving and emerging pre-commercial technologies, b) perform techno-economic feasibility assessments for existing commercial and near-commercial advanced technologies, and c) develop an innovation strategy for specific elements of particular technologies, including demonstration efforts.

8.2.3.1 Monitoring and feasibility assessment

Emerging technologies such as oxy-fuel combustion and carbon capture and storage are still in the early stages of innovation and their technology trajectory will evolve as industrialized countries invest in RD&D for these technologies. Other technologies (such as USC-PC, IGCC, and PFBC) are already demonstrated and deployed in several countries.[435] Given this evolving technology landscape, it is very important to keep track of global technological developments as well as the economics of these plants. At the same time, detailed techno-economic assessment for Indian coals and conditions are very much needed for key technologies that seem particularly relevant to the Indian context. Site-specific factors, such as the coal properties, ambient conditions, and the temperature and availability of cooling water, can strongly affect efficiency; similarly, electricity cost estimates using different technologies vary widely in published studies, and the difference in cost between technologies is smaller than the uncertainty in each of these estimates (see section 7.1). Thus, a proper comparison of different technologies needs engineering-based analyses using technical and economic factors/assumptions that are valid in the Indian context.

Hence, a monitoring and feasibility assessment institution (or a program within an existing institution) needs to be established to continuously evaluate the status of emerging and near-commercial technologies. This should include detailed engineering and economic analyses of new technologies as well as assessment of the financial and institutional capacity needed for deployment. Technology assessments must address the various challenges and constraints faced by the sector, and hence the overall vision and objectives must be determined through a deliberative process involving all stakeholders. The technology assessment process must involve the government, key enterprises such as BHEL and NTPC, and private sector representatives. The institution could be funded by a consortium of utilities as with EPRI in the United States or CRIEPI in Japan. Such an arrangement will also increase the participation of multiple practitioners in the process, thereby enhancing the robustness of the technology assessments.

Furthermore, international linkages with RD^3 programs and institutions worldwide must be created, as appropriate and necessary. For example, strategic interactions with U.S., European, and Japanese government energy agencies and laboratories, EPRI, CRIEPI, the U.S. National Research Council, coal industry from various countries (U.S., Australia, and South Africa), and U.S. and Australian geological agencies could prove to useful for technology assessments in India. It is also important that the results of this monitoring and feasibility assessment program be the basis for decision-making on the strategic research, development, and demonstration program described below.

[435] IGCC is not commercially deployed yet and it is still being fine-tuned.

8.2.3.2 Strategic research, development, and demonstration

While many advanced technologies may not be deployable immediately in India, a set of strategic research, development, and demonstration activities can be initiated on selected coal-power generation technologies that potentially might be of relevance to India in the coming years. Such activities should especially focus on:

a) specific technological advances needed for adapting these technologies to the Indian context,

b) some basic elements of these technologies that leverage existing capabilities and add value to the country's industrial base regardless of which technological option may be implemented, and

c) initiation of demonstration and early deployment projects in case of particularly promising technologies.

For example, research on advanced materials and development of control systems for advanced combustion technologies could be considered. In addition, research on modeling (such as computational fluid dynamics) of combustion and gasification processes would be useful for engineering design of new power plants and for improving the performance of existing plants. One can also assess possibilities for developing and testing carbon capture technologies in existing Indian power plants—this could provide information about retrofitting options in India. Furthermore, new indigenous capture technologies that are better suited for plants using Indian coals could be explored.[436] These activities should leverage existing capabilities and add value to the country's industrial base.

Technology demonstration and early deployment should be strategically planned so that lessons from these activities are integrated into a well-defined action plan. New ideas and options must be considered. For example, given that India is likely to import coal on a sustained basis, one can consider the demonstration of an IGCC plant using imported coal, rather than Indian coals. This will allow the use of standard gasification technologies, and could help utilities in learning to reliably operate a new technological system, without having to solve simultaneously the hard problem of gasifying Indian coals. This will also test the IGCC's often-touted environmental performance in Indian conditions. Operational and cost data from such an IGCC demonstration will be highly relevant for designing future IGCC plants, even those designed for Indian coals. Similarly, carbon capture and storage technologies could be tested in Indian power plants (in either combustion or gasification plants) using imported coal and other feedstock such as petcoke. The use of imported coal with 'standard' technologies available worldwide, such as entrained-flow gasifiers, could also increase opportunities for demonstrating CCS technologies. Thus, increased coal imports would call for the examination of a two-track technology strategy – one for domestic coal and another for imported coal.

Such planning is probably best led by a government agency (possibly the Planning Commission), but it requires the involvement of multiple relevant stakeholders in India, including key public sector enterprises such as NTPC and BHEL as well as private industries and utilities. Strategic partnerships and collaborations with international research initiatives could also strengthen this planning process. In addition to government funding for technology innovation, international

[436] For example, new capture technologies might be devised which do not require high purity flue gases.

funding could be sought for leveraging government support for demonstration projects (for example, through the Clean Development Mechanism or its successor programs). At the same time, domestic innovation capability must be strengthened significantly (see section 8.3.5 below).

8.2.4 Enforce and tighten local environmental pollution controls

Local environmental protection is already an important goal for the government, since the impact of coal-based power plants on the environment has been significant (see section 3.3). Current environmental regulations are primarily focused on controlling particulate emissions, and electrostatic precipitators (ESPs) that are modified for Indian coal ash are used in all plants. However, stack emissions of sulfur oxide and nitrogen oxide emissions are not regulated, and only ambient air concentrations are monitored and regulated for these pollutants. The focus of regulations is on dispersal, rather than control, of these pollutants. In many cases, even these regulations are not effectively enforced, and nearly a third of the plants continue to violate these norms, while continuing to generate power.

Since the pressure to improve the environmental performance of power plants will likely increase in the future, it is important to better enforce and tighten local environmental pollution controls.[437] This will help meet one of the major future challenges for the power sector through the implementation of suitable technologies such as flue-gas desulfurization units and low-NOx burners. The resulting experience will also be useful for other advanced combustion technologies. Furthermore, as discussed in section 6.6.1, a clean flue-gas is a prerequisite for the economic use of post-combustion carbon capture technologies, such as amine scrubbing, and also for pre-combustion capture, such as in an IGCC. Thus, there are significant synergies between reducing local environmental pollution and increasing the potential for carbon capture in the future.

The Ministry of Environment and Forests (MoEF), which has the primary responsibility for creating and enforcing environmental regulations, is working with the industry on developing better emission standards. The Corporate Responsibility for Environmental Protection (CREP) charter (see section 3.3) aims to get non-compliant plants to install pollution control equipment, establish tighter pollution standards, get power plants to use beneficiated coal, fully utilize flyash, and promote the use of new cleaner coal technologies. While the CREP process has made some progress, it is important for the Ministry to broaden this process to include a wider range of stakeholders and work with industry and environmental groups to initiate a process for determining an ‘environmental roadmap’ (with specific goals and timetables) for the coal power sector. Where there is already consensus on the fact that environmental regulation of pollutants from coal power plants will have to be strengthened, the key issues are what kinds of regulations, when they will be imposed, and how they will be enforced.

Furthermore, given that MoEF is relatively weak in comparison to the other ministries and it has historically been hamstrung by lack of widespread political and popular support (see section 3.3.1), a key driver to push the environmental agenda ahead in the country is public pressure and participation. Only when there is political will and public pressure, will MoEF devise better

[437] This would require India to consider both command and control approaches, as well as market-based instruments, such as pollution taxes, tradable permits, etc.

policies and regulations, and enforce these regulations better. As discussed in section 3.3.1, the government bureaucracy so far has allowed little space for effective public participation in environmental decision-making. Including the environment in developmental planning implies resolving the question of how to channel economic growth to effectively reduce poverty and protect the environment. Rapid and haphazard growth without regard for environment or social issues will exacerbate poverty, rather than reducing it. Hence, it is crucial for the country to determine the appropriate (political) spaces wherein environmental goals can be furthered.[438]

8.2.5 Focused effort on mapping geological storage locations in India

As discussed in chapter 6.6.3, geological storage in underground saline aquifers is currently the most promising option for storing large quantities of CO_2. However, storage in geological media requires detailed assessments of specific storage locations and capacity within these locations. Currently, only broad first-of-a-kind estimates of storage capacity are available in the country, and there is a strong need for detailed site-specific assessment of storage mechanism and capacity in potential on-shore and off-shore locations. Furthermore, capture of CO_2 in power plants is meaningless unless realistic options for storing the captured CO_2 are also realized at the same time. Thus, it is important to embark, as early as possible, on detailed reservoir mapping and specific site characterizations for large-scale geological storage (of the order of a million tons of CO_2 per year).

A good understanding of the CO_2 storage sites and reservoir capacities will help inform any decisions about the deployment of power generation technologies with carbon capture. It might also influence current siting decisions for coal power plants. For example, if off-shore storage capacity is deemed to be quite high and comparatively economical, it would behoove power planners to consider siting power plants close to the coasts. Such plants might also benefit from being able to economically utilize imported coal. On the other hand, if on-shore storage proves to be more economical, then power plants can be sited close to these locations. Planning of this kind can only happen after storage site locations are well mapped, along with geological assessments of reservoir capacities. Such maps will be also useful to assess economic impacts of retrofitting existing/planned power plants with CCS technology.

Consequently, it is crucial that exploration efforts, as well as strategic R&D programs (and any relevant demonstration projects), be initiated to estimate CO_2 storage locations and capacity in India. This effort is complementary to the technology monitoring and feasibility program discussed above, and may be led by the Directorate General of Hydrocarbons (DGH), Geological Survey of India, and oil and natural gas exploration industries. DGH and ONGC might already be able to make better estimates for storage capacity in oil and gas fields based on existing data on oil and gas reservoirs. Many of the techniques for oil and gas exploration can also be translated for assessing reservoirs for CO_2 storage and monitoring.

With coordinated efforts between the GSI, DGH, ONGC and OIL, much of the uncertainty regarding geological storage in India can be reduced, and a map of storage sites with capacities based on geology (rather than on surface area calculations) can be generated. ONGC may also consider pilot scale projects to inject CO_2 depleted oil wells for enhanced oil recovery. As India

[438] For example, the states could take the lead in creating (dis)incentives for environmental protection.

does not seem to have large, natural CO_2 sources, CO_2 from refineries or fertilizer plants (see section 6.6.4) may be piped to the oil and gas fields for EOR. These low-cost CO_2 sources can also be considered for pilots-scale and demonstration of technologies needed for geological storage in India. Estimates should also be made for CO_2 storage capacity in deep unmineable coal beds and for enhanced CBM. Furthermore, given that Indian sedimentary basins are not yet well explored, the exploration and assessments for CO_2 storage will also help buttress the geological exploration effort for identifying new hydrocarbon and coal resources in the country.

Regarding information dissemination from the storage assessment studies, it maybe prudent not to release all detailed geological information from such exploration, but consolidated data and information should be made public. An independent board or commission could be set up to ensure the reliability of the data.

Finally, India's participation in international programs, such as the Carbon Sequestration Leadership Forum, should be leveraged to increase capacity within the country for geological assessments. India could also take the lead in building regional partnerships in South and Southeast Asia for carbon storage assessments. In addition to geological assessments, India should also aim to develop capacity for storage and monitoring technologies.

8.3 Enabling Conditions for implementing the roadmap

While the policy elements discussed above will put the Indian power sector on path towards meeting its future challenges, several broader enabling conditions and activities are necessary to ensure the successful implementation of these policies. We focus here particularly on what we regard to be key issues, namely, a better understanding and use of coal resources and improving coal sector institutions, improved systems of technology and policy innovation, institutional coordination, need for domestic policy analysis, and international action and cooperation on climate change mitigation.

8.3.1 Changes and improvements in the coal sector

Sustained and sustainable growth of the Indian coal power sector requires changes and better policies in the coal sector. To begin with, better energy planning and policies in the coal power sector requires a much better understanding of domestic coal reserves, especially given the significant uncertainty about the extractability of coal resources. There are considerable problems in the way Indian coal resources are assessed, as detailed in section 4.1.1. The current definition for categorizing coal resources in India is heavily biased towards geological classification without taking current techno-economics into account. Based on recent estimates (CMPDIL, 2001; Chand, 2005; Chikkatur, 2005; Ministry of Coal, 2005a), Indian coal reserves are thought to be about 44 billion tons (BT), out of a total resource inventory of 248 BT. These current reserves might be expected to last between 30-60 years, depending on the rate of domestic coal production (Chikkatur, 2005). This relatively-short lifetime is in sharp contrast to the general assumption that Indian coal will last more than 200 years – an assumption predicated on extracting all the resources without accounting for technology or economics. Certainly, the amount of reserves, and hence the coal availability lifetime, can be increased by more investment in coal reserve assessment and technological investment in the coal sector, but it cannot be taken as a given. Reduction of uncertainties and greater investment in the coal sector will help not just with better energy planning, but also for sustained growth in the coal-power sector. Reformulating the coal resources according to United Nations Framework Convention (UNFC) standards is only a first step, but a systematic and independent assessment of coal resources, particular those in deep seams, is necessary to encourage efficient mining practices and new technologies such as underground coal gasification and coal-bed methane.

The coal sector must also increase its productivity and implement effective reforms to increase productivity. It is essential to encourage and promote underground mining techniques to access deeper coal seams. Existing opencast mining pits must also be reclaimed and restored after they are used up. This will build the necessary goodwill amongst local people. There will be inevitable conflicts between increased mining and environmental protection. Therefore, it is important to initiate discussions among various stakeholders, including the affected public, on developing a consensus on how to increase coal production with better environmental and social management. There is a need for new ideas on this issue. The recent Expert Committee report (Ministry of Coal, 2005a) is a good start and it might help catalyze the necessary changes in the coal mining sector.

Investing in coal transportation infrastructure is also essential. Constraints on domestic coal production as well as the limited availability of siting locations for future pithead plants might lead to more coal being transported across the country.[439] Given that railways account for most of the coal transportation, dedicated railway corridors for coal are necessary.[440] The railway corridors must connect load centers not only with domestic mining centers, but also various ports that are expected to handle coal imports. Coal-handling infrastructure in ports must also be enhanced to accept more coal imports. Furthermore, increased coal traffic must not lead to an increase in coal theft and reduction in coal quality. New approaches for providing small consumers with legitimate coal supply might help reduce theft. The railways (and the road transport) must accept responsibility for maintaining coal quality and quantity during transport – information technology might be able to help in this regard. Investment in overall transportation infrastructure must be sufficient enough to handle the increased coal traffic in the country; without such investment, it becomes difficult to meet the expected increase in coal demand.

Poor quality of coal is another serious constraint on developing new technologies based on domestic coal. Ash content in Indian coals has been increasing over the past three decades, primarily because of increased opencast mining and production of coal from inherently inferior grades of coal (see section 4.1.6). Widespread use of advanced combustion technologies might hinge on the availability of beneficiated coal with reduced ash-content. Beneficiation of coking coal is already well-established, and there are now washeries for non-coking coal as well, but there needs to be much more focused effort to increase economic washing. Hence, it is essential to provide incentives for setting up of coal washeries, and also use the washery middlings for power generation in CFBC boilers. One of the first steps would be to price the coal based on its calorific value. The use of better metrics for coal quality (for example, a narrow band of measured calorific value of coal is better than the existing grading system) will encourage the construction of more washing facilities for thermal coal. The higher price of washed coal will be offset by the gained environmental and transportation benefits. In addition, a contract-based coal market, rather than the existing system of government-determined linkages, might also improve the market for coal.

Finally, given the increasing gap between the demand for coal and domestic coal production, India must be prepared for increasing its coal imports both in the short term and in the long-term. India must secure long-term coal contracts to lock in low prices for appropriate quantities, based on a conservative estimate of import need. From a strategic perspective, it is useful for India to secure long-term contracts for a supply of low-price, higher-calorific value coals from foreign sources now, so that India can hedge against future coal price increases. Furthermore, long-term energy security is enhanced by extending the life of domestic coal resources, and coal imports might be used as a substitute for domestic coal as demand increase.

---

[439] Coal-based power plants cannot be sited anywhere. The plants must have access to sufficient amounts of water, and hence they have to be located near rivers or dams. They must also be sited in a place with access to coal supply, which can be near a coal mine mouth (pithead power plants) with merry-go-round rail facilities, or be close to railroads and/or port facilities. They also require large tracts of land to be used for storing and land-filling ash.

[440] Work on this issue is already underway with the creation of a new company to build these corridors. See: http://www.indianrailways.gov.in/DFCC/

8.3.2 Institutional and Financial health of power sector

As mentioned in section 2.4, the Indian power sector has seen dramatic institutional changes in the past decade and a half. Unfortunately, the experience with the liberalization and restructuring of the power sector has to be seen as mixed at best, this outcome resulting from the interlinked factors of poor design of the "reformed" power sector (i.e., not fully suitable for the Indian context), inept management of the reform process, and deficient governance in practice (Dubash and Singh, 2005b; D. P. Sharma et al., 2005; A. Singh, 2006; Dubash and D. Narasimha Rao, 2007).

In the decade after the initiation of these changes, the technical performance of the power sector did not improve much – the T&D losses as well as peak and energy shortages stayed almost the same, although the PLF did improve somewhat (D. P. Sharma et al., 2005). The economic performance of the sector remained woeful – despite tariff revisions, the losses of the SEBs continued to mount, their cost recovery through tariff continued to decrease, and the rate of return dropped precipitously to less than - 40% by 2002 (D. P. Sharma et al., 2005). Such a precarious financial situation impedes significantly the ability of SEBs to raise funds for new power plants or sign power purchase agreements with power generators (A. Singh, 2006).

The regulatory institutions have been less than fully effective because of lack of political support, weak capacity, ambiguity in operating procedures and norms, and aversion to conflict with entrenched interests and politics (Dubash and D. Narasimha Rao, 2007).

Although improvements in the institutional and financial health of the sector will not come easily, there is hope as there is greater scrutiny of the performance of the reforms, better understanding that successful reforms necessarily will require a tailoring to the Indian context, and institutional learning and capacity building. Hybrid approaches to power-sector reform will have to be considered, along with greater attention to planning for the transition period (Dubash and Singh, 2005b). Regulatory institutions will certainly have to be strengthened by giving them greater credibility and enabling the development of their capacity; regulators themselves must proactively act and cooperate to improve and strengthen regulatory practices, and improve stakeholder participation (Dubash and D. Narasimha Rao, 2007).

At the same time, though, there has to be specific focus on measures such as demand-side management, improvements in efficiency of existing power plants, and investments in improvement of transmission infrastructure (that also will ultimately enable "open access") will all help in improving the performance of the power sector. There is also some expectation that open access, by giving industrial customers the choice to exit the system, will force the facing-up to subsidy issues (Dubash and Singh, 2005b; A. Singh, 2006), which has been the bane of the SEBs.

Ultimately, though, the institutional and financial health of the sector cannot be delinked from the politics of the power sector. The institutional transformation of the power sector has to contend with entrenched interests and political gamesmanship. This probably is the most intractable problem facing the power sector; a greater and more open public debate on these issues offers the only chance of tackling them.

8.3.3 Inter-ministerial and regulatory coordination

The institutional landscape in the country's power sector has evolved significantly over the past decade, and it will continue to evolve. The impact of the market-oriented policies and practices in the power sector will only become clear in the coming decades. These ongoing structural changes add further complexity to an already complex policy-making and planning environment in the Indian power sector, with multiple institutions and actors that have different interests. Therefore, there is a great need for improved inter-ministerial and regulatory coordination. Some of the key ministries and their role in the Indian coal power sector are briefly summarized below.

The Ministry of Power is primarily responsible for the development of electricity in India, being centrally involved in planning, policy formulation, processing of project and investment decisions, project monitoring, human resource development, and implementation of electricity legislations (Ministry of Power, 2006). It is also in charge of matters related to key organizations in all sectors: NTPC (generation), PFC (finance), Power Grid Corporation of India Limited (transmission), Bureau of Energy Efficiency (efficiency), Central Power Research Institute (research), and the Central Electricity Authority (techno-economic assessments). Thus, despite the existence of an independent regulatory commission, reorganization of state utilities, and a greater push for private sector involvement, the Ministry of Power wields considerable influence on the Indian power sector. At the same time, the Ministry of Finance also plays a key role in power sector policies for obvious reasons.

Similarly, in power manufacturing, the Ministry of Heavy Industry is responsible for planning and growth of the country's engineering industries, and it is in administrative control of BHEL. It interacts with various industry councils, assists industry through policy initiatives, resolves problems relating to tariffs and trade, and helps in technological collaboration and R&D.[441] The Ministry of Coal is responsible for the planning, exploration, and development of the coal and lignite resources in the country. It administratively controls Coal India Limited (and its subsidiaries) and Neyveli Lignite Corporation. The planning for coal exploration and mining is determined by the expected demand for coal in the power and industrial sectors. The Ministry of Environment and Forests (MoEF) has the responsibility for creating and enforcing environmental regulations. It is, however, relatively weak in comparison to the other ministries.

The Planning Commission is the nodal organization that is expected to integrate the developmental priorities of the different ministries (discussed above) and determine a holistic plan that meets the country's objectives. Although the Commission's national plans and proposed outlays are no longer considered to be authoritative, the Commission plays an integrative role for determining priorities and formulating policy guidelines.

Given the many ministries, public sector enterprises, and organizations involved in the coal power sector, the actions and policies of any single actor can affect the power sector policy, including technology policies. Fortunately, there already are some ongoing efforts to increase coordination and devise coherent policies for the country's overall energy sector. In 2005, an Energy Coordination Committee was set up in the Prime Minister's Office for better inter-

[441] See: http://dhi.nic.in/role01.htm.

ministerial coordination and integrative decision making in the area of energy planning and security.[442] Furthermore, the Planning Commission's recent Integrated Energy Policy report has attempted to devise holistic policies in the energy sector and its demand forecast estimates and policy recommendations have used for the formulation of the 11th National Plan.

In addition to the coordination of the different ministries, the impact and influence of independent regulatory agencies are particularly important. As discussed in section 2.4, independent regulation was introduced in the power sector by the World Bank, through its support of electricity restructuring in several Indian states. The quasi-judicial Central Electricity Regulatory Commission (CERC) was established in 1988, with jurisdiction over setting tariffs for electricity purchased from Central utilities and advisory powers for the Central government on new guidelines and policies (CERC, 2000a). Meanwhile, the Electricity Act, 2003 (EA 2003) has called for independent regulatory oversight, unbundling and privatization of vertically-integrated state utilities, and introduction of competitive distribution.

In this changing institutional environment, the regulators are trying to increase competition and reduce the cost of electricity for consumers, while maintaining a good investment climate for the utilities to add capacity to ameliorate existing power shortages and meet expected demand growth. The design of regulations and incentives can promote or impede the deployment of new technologies. On the other hand, emergence of new technologies may also have implications for the power sector, which should also be reflected in appropriate regulation. A close coupling between the technology roadmapping and regulatory processes will be important for realizing the potential that technological advances can offer to coal-based power generation. For example, current regulations allow for additional capital expenditure needed to meet environmental standards and consider these assets for depreciation if environmental standards are complied in the previous period. However, it is not clear as to how the regulators would deal with installing the more expensive climate mitigation technologies, as it will likely increase the cost of the power dramatically, especially if it implies retrofitting of existing power plants. Similarly, increasing privatization in distribution and the introduction of competitive bidding for generation will influence the nature of technology innovation and deployment. Another important issue is to determine the ways in which the higher cost of cleaner technologies can be defrayed. Since consumers will eventually bear these costs, appropriate policy and regulatory interventions must be devised to reduce the impact on weaker sections of society.

These and other issues will need to be analyzed and addressed by regulators. Although regulators are generally inclined support advanced technologies, regulators will need to work with MoEF, the Ministry of Power, BHEL, and the utilities to introduce suitable mechanisms that promote the introduction of suitable power generation technologies.

8.3.4 Improved technological analysis and innovation systems

Improved technology innovation in the Indian coal power sector requires an infusion of significant domestic financial resources and institutional changes in order to successfully contribute to the development and deployment of new technologies and compete with other international firms. Technological capacity is not generated by simply producing more engineers

[442] See: http://pmindia.nic.in/eccbody.htm

and scientists, nor is it gained automatically through deployment, but rather, it derives from deliberate R&D and learning-by-doing, which are based partly on production experience, import of knowledge and technologies from foreign sources, and from a systematic process of investment in indigenous creation of knowledge and skills (Lall, 1987).

The implementation of any technology roadmap is very much dependent on the existence of vibrant energy technology innovation processes in the country. Issues related to innovation in the Indian power sector are discussed below (see also section 4.3.1.1):

- Limited technology analyses: Current technology analyses are limited and mainly focused on technical issues. Technical assessments often have a short-term focus (in concert with the five-year plan process), which can preclude identification of key data and technology gaps for the medium-to-long term and ways to fill them. Moreover, inputs from different agencies are often taken as is, without much critical analysis of the data and the underlying assumptions. Hence, it is essential that technology analysis and assessments be broadened to include a range of existing and emerging technologies through ongoing monitoring of global technology development, as well as detailed techno-economic assessments of technologies in the Indian context (see section 7.1).

  Such critical analyses must focus on both the short term and the long term and include a broader cross-section of stakeholders to ensure that their concerns are addressed in the analysis and to build consensus on the suitability of technology options for the country—this latter aspect is particularly important for developing effective technology policies and shaping future innovation efforts. Academia and non-governmental organizations must also seriously engage in technology policy analyses to complement and extend the activities of the public sector enterprises.

- Scale and scope of innovation efforts: Currently, the scale and scope of R&D efforts in clean coal technologies are not commensurate with the challenges. Although there are significant R&D efforts relating to advanced coal-based generation technologies in the country (most notably in BHEL, IICT, and more recently, NTPC), larger and better focused efforts are needed to meet, in a strategic fashion, the clean-coal technology needs of the country. Once again, the role of the government as the coordinator and a lead funder of these efforts is critical (as in other countries, cf. the role of US government in the US CCT programs; see Ghosh (2005) and NRC (1995)). In addition to increased funding, attention must also be paid to better-designed and well-coordinated RD^3 programs – a well-planned program can be critical in helping implement technologies and conveying the learning from these experiences back into R&D efforts.

- Need for increased funding and new mechanisms for funding: R&D expenditure in public sector institutions, particularly BHEL, dominates the Indian CCT funding. Nonetheless, BHEL's expenditure on R&D pales in comparison to its international competitors such as Alstom and Siemens. In 2004-05, BHEL spent $28 million on R&D,[443] whereas Alstom

[443] In 2006-07, it is expected to increase the R&D funding substantially to about $45 million. See: http://news.oneindia.in/2006/04/12/bhel-plans-rs-200-cr-rd-fund-1144843530.html

had an overall R&D expenditure of $417 million and the power division of Siemens spent $525 million in 2004 on R&D, and (Alstom, 2005a; Siemens, 2005). In 2004, Siemens power R&D expenditure was 3.8% of sales and the corresponding number for BHEL (i.e., overall R&D as a percentage of total sales) was 1.2%.

Furthermore, many of the technical activities in the coal power sector continue to rely on foreign sources of funding. For example, the BHEL R&D facilities were supported technically and financially by USAID funds. USAID also supported CENPEEP to improve the efficiency of Indian power plants and the recent feasibility study of assessing technologies for IGCC in India. Such studies typically use foreign consultants, which eliminate opportunities for Indian consultants and researchers to engage in such analyses, which would increase their capabilities. For example, Nexant was the key consultant for the recent IGCC assessment for India.

In addition to directing public sector enterprises to increase their R&D expenditure, the government can create a pool of R&D funds that different agencies can vie for through a competitive project selection process. This would bring peer review and accountability in R&D project selection. Private-sector participation in energy technology innovation activities must be encouraged through cost-sharing programs and competitive bidding for projects. This also means the involvement of multiple institutions in demonstration and deployment programs. An example of such an activity is the BHEL-NTPC joint IGCC demonstration project.

- Sunset clauses: It is important for innovation activities to be results-oriented. Therefore, there must be well-defined milestones for these programs, and they must have a limited (although adequate) time horizon. Results-driven programs will also lead to the development of metrics for success (with collection of relevant data) and regular independent reviews – all of which will be positive for encouraging innovation in India.

- Institutional linkages and coordination: India's innovation system is relatively small, largely fragmented, and performs well only in a few sectors. Government institutions are currently the main performers of R&D, which is in contrast to most industrialized countries where the private sector is key driver of R&D and innovation—in the United States, for example, private industry performs about 70% of the total R&D. There is little concerted effort to coordinate the development of new technologies in India, and R&D efforts are often not synergistic. Innovation of new technologies requires strategic, sustained interactions between academic researchers, government and private sector R&D labs, and industries (manufacturers and utilities); currently, such interactions take place on an ad-hoc basis. Successful innovation requires close linkages among private-sector R&D labs, government labs, and academic researchers. Collaboration and coordination among these institutions must be promoted through appropriately designed funding and other incentives.

- Linkages to international R&D activities: Given that there are a range of ongoing international efforts on clean-coal technologies, the utility of linking to, and learning from, these efforts cannot be overstated. This can be carried out, for example, through the monitoring and assessment program that was discussed earlier, and by having regular technical workshops that invite personnel from international programs and bilateral visiting researcher programs.

- Maintaining an active scientific manpower: Successful technology innovation also requires the active participation and continued engagement of scientists and engineers from various institutions (academia, industry, and government laboratories). Incentives must be provided to scientists and engineers for encouraging them to come up with new innovative solutions to problems. There is already significant indigenous technical capability and scientific and engineering workforce for manufacturing, designing, and developing various elements of power plant technologies within public sector units such as BHEL and NTPC, and they should not be neglected. Furthermore, promoting the country's energy security requires the maintenance of a strong domestic manufacturing capability and self-reliance, in terms of both technical and human capacities. Trained Indian engineers and specialists should be able to successfully operate and maintain power plants, without outside help and intervention. Designs for, and manufacturing capacity of spare parts and other key equipments, should also be indigenously available.

8.3.5 Need for domestically-driven coherent energy policy analyses

As discussed in section 4.4.4, limited attention paid to policy research and analysis in the country has greatly impeded the development of a domestically led coherent, long-term energy policy and its strategic implementation. The policy-related analytical capacity available in domestic Indian institutions is limited. Even in cases where there may be relevant expertise in the government, the enormous and varied workload precludes the possibility of devoting sustained attention to long-term issues. A significant portion of the domestic capabilities for carrying out such analysis in the government lies currently in the Planning Commission but its efforts are limited by the small size of the energy-planning group, which has to deal with a whole myriad of issues (economics, regulation, technology, etc. relating to various energy sub-sectors). Government institutions, such as the Planning Commission and the Power Ministry, should prepare White Papers that discuss significant policy issues and possible approaches towards them. These White Papers must be distributed for public comment and debate.[444] Furthermore, the academics, NGOs, and think-tanks need to pay more attention to power-sector technology policies and need to build up the necessary capacity needed to do the required analysis. Very few NGOs and academics current engage actively in public policy formulation and analysis, when they do take place, it is primarily as experts or in an advisory role to the government. Often these interactions are on a one-to-one basis rather than open, multi-institutional discussions that can be more productive. The government bureaucracy must also be flexible enough to engage academics and multiple NGOs in policy formulation and analysis.

[444] For example, the draft report of Integrated Energy Policy was placed on the Planning Commission's website and comments on this draft were requested. Given that significant parts of the final report were different from the draft, one can conclude that public comments did have had some influence. However, the Planning Commission has not released any compilations of received comments, nor has it stated how these comments were incorporated in its final report.

Development of long term policies and strategic planning is often limited by the endemic "panic" or "catch-up" mode of operations in the power sector (see section 4.4), which results in disproportionate emphasis by planners on generation. This emphasis is further reinforced by the media and public's attention given to the shortfalls in the planned capacity additions. Hence, the country's energy analysts and planners also tend to focus more on generation rather than on long-term strategic policies and planning, including resolving transmission and distribution issues. Domestic energy policy analysts (within and outside the government) must be given necessary the resources and time needed to study the long-term energy and technology policy issues. It would benefit the power sector enormously if the government takes a step back and seriously engage in a technology and policy roadmapping process.

Furthermore, external organizations have played a significant role in shaping the power-sector and climate policies and priorities in the country.[445] For example, aid agencies such as USAID and Department for International Development-UK (DFID) helped initiate the restructuring of the Indian power sector, through funding that catalyzed major World Bank projects in this area and leveraged its funds for a large impact (Dubash and Rajan, 2001). Lack of local expertise allows for the injection, acceptance, and diffusion of policy approaches, often developed by international consultants, without full consideration of how these approaches might play out in the Indian context. This has now heightened sensitivities amongst the public and many policy makers against new ideas and policies, particularly those pushed by international agencies.

It is, therefore, essential to build and expand independent policy research and analysis capacity in the country. Better policy research capacity also will help in integration of power-sector policy with cross-sectoral issues such as national security, environment, and labor. This is particularly important as the power sector is in a period of transition and is faced with major issues such as labor relations resulting from restructuring, the approach for increasing competition in the sector, the role and impact of increasing private sector involvement, etc. At the same time, there are other key emerging issues such as energy security and climate change that also have significant policy implications for the sector.

8.3.6 Climate change mitigation and international cooperation

Reducing GHG emissions to alleviate the impacts of global climate change is poised to become a critical challenge for the production of cleaner energy, in particular for electricity generation. Moreover, the GHG-mitigation challenge comes at a time when India is already facing extremely pressing challenges, such as the urgent need to expand its energy sector to fuel economic and social development and to enhance energy access for all its citizens. Despite having contributed minimally to the climate change problem, India is likely to bear a significant brunt of a changed climate (see section 3.4.2). Hence, the urgent need for action to tackle this problem is becoming more apparent and accepted in policy circles. An indication of this change is the recent proposal by India's Finance Minister to create an expert panel to study the impacts of climate change and mitigation options in India.[446]

[445] See, for example, (Kandlikar and Sagar, 1999).and (Dubash and Rajan, 2001).
[446] See: The Hindu Business Line, "Climate Change on India's radar now", May 1, 2007; http://www.blonnet.com/2007/03/01/stories/2007030103490200.htm.

As discussed in section 3.4, the nature and timing of international negotiations on global GHG mitigation will be crucial in determining the course of GHG reduction activities in India. The negotiations will shape when and how India will move beyond the 'no-regret' policies and activities, and aim for significant GHG reductions. Ultimately, it is in India's interest that the global negotiations on climate change yield a stringent GHG-mitigation regime, although it does not have any leverage on the major GHG polluters. In this context, it might be useful for India and other developing countries to first negotiate amongst themselves to develop a framework under which it may make sense for them to take on commitments as part of the UNFCCC negotiation process. Issues of equity related to sharing atmospheric sinks and burden of mitigation, technology transfer and adaptation will likely be pivotal to these negotiations and the eventual allocation of GHG-mitigation commitments. Another important issue will be the availability and access to GHG-mitigating technologies, which are often developed first in industrialized countries—for example, carbon capture, storage and monitoring technologies are an important subset of such GHG mitigation technologies.

Deep reductions of GHG emissions in the Indian coal power sector require strong political will, public pressure, and a coherent set of policies, all of which will take some time to emerge. The practicalities of undertaking any large GHG-mitigation efforts are also complicated by lack of demonstrated progress on the part of richer countries. These countries have done little despite their enormous technical and economic capabilities. Thus, leadership from Annex-I countries, particularly the United States, is essential for India and other developing countries to consider GHG-mitigation commitments.

In addition to global negotiations and implementation in richer countries, political will in India for climate change mitigation will primarily be driven by perceived and real impacts of climate change and public pressure. This can be facilitated by scientific assessments on the future and current impacts of climate change on various economic activities in India (for example, the impact of changing monsoonal patterns on agricultural productivity, etc.).

International action and cooperation will play a very important role in accelerating the development and deployment of lower-GHG coal-power technologies in India. The international community can help promote the transition to lower-GHG coal-power technologies in India in several ways:

a) <u>Reducing their own GHG emissions:</u> Industrialized countries must lead by example and implement concrete policies and actions to reduce their GHG emissions. This will advance the likelihood of India developing and implementing specific climate-mitigation policies that go beyond the 'no-regret' policies such as enhancing energy efficiency.

b) <u>Low-GHG technology and policy innovation:</u> Climate change mitigation activities in industrialized countries will result in the development and deployment of lower-GHG policies and coal-power technologies (such as CCS). Such innovations will increase the range of technology and policy options available to India and lower technology costs.

c) <u>Helping increase technological capacity in India:</u> Industrialized countries can assist India in technology analysis as well as deepening its technology capabilities to facilitate the selection of technologies best-suited to the Indian context and their adaptation to local conditions. There is, of course, a significant onus on Indian institutions to ensure that international collaboration is effective not only for climate-mitigation but also for the broader development goals.

In addition, the need for (and the choice and roles of) foreign partners and collaborators at each stage of the technology innovation process must be assessed, so that they can help overcome lacunae in domestic capabilities. Linkages with appropriate international research organizations (such as the national laboratories in industrialized countries) and engineering firms might add significant value and speed up basic and applied research for specific technologies. It might also be necessary to utilize the expertise of foreign analysts and consultants for policy analysis and technology assessments, although domestic experts must remain involved to ensure a suitable incorporation of local perspectives and build up indigenous analysis capacity. Finally, commercial tie-ups and joint venture projects become more feasible for the technology deployment and commercialization phase. In such cases, it is very important to assess whether the foreign collaborations are need-based and how foreign linkages and tie-ups can best further India's long-term technology strategy.

Provision of international financial support for carbon mitigation (particularly for CCS) in developing countries through the Clean Development Mechanism and its successors might also increase the possibility for their deployment in India. However, funding by itself is insufficient, and internationally supported capacity-building activities would be needed to strengthen the technological capacity in the sector and help lower GHG emissions in the long run.

On the other hand, it is important to note that excessive and premature push on GHG mitigation in India, particularly by international agencies, might be counter-productive, especially if it is not clear what technological options make sense from the long-term perspective and if their technological and economic feasibility is not well-demonstrated globally.

8.4 Way Forward—process and institutions

As mentioned earlier, the roadmap and the implementation program presented in this paper is meant to be illustrative rather than definitive. While the development of a roadmap for coal-power generation is extremely important, careful attention must be paid to the process that leads to this roadmap.

A precursor to technology roadmapping for coal-power generation technologies is to assess the state of domestic coal resources and their exploitation potential, since the specifics of a roadmap will necessarily depend on the availability and choice of coal. Hence, it is necessary to begin the roadmapping process with a critical assessment of the current state of coal sector and an analysis of future steps for developing suitable data and approaches to better assess and exploit the country's coal resources. This will not only provide a solid foundation on which to carry out the technology roadmapping, but also highlight the fact that decision-making for coal-power cannot be delinked from decisions made in the coal sector.

A consultative and transparent process that includes all key stakeholders is critical for developing a roadmap. As mentioned earlier in section 5.2, key stakeholders include end-consumers, technology manufacturers, coal producers and transporters, utilities, project financiers, relevant government ministries, agencies, academics, NGOs, and other citizen groups. A roadmap that represents the consensus of all these stakeholders is likely to be much more robust than a roadmap put together in a top-down or technocratic fashion since it will include a diversity of perspectives and concerns. It should be made clear that a consensus outcome may not necessarily incorporate all views of all participants but it will necessarily require the engagement of all the participants and full consideration of their views even if the final document is not fully aligned with each of these views.

The recent history of restructuring in the power sector indicates that external agencies have often played a central role in initiating and influencing changes in the sector and this often overwhelms, biases, or excludes home-grown ideas, options and analysis. Therefore, it is best if the stakeholder process for technology roadmapping is domestically driven, managed, and led by the government (rather than by international or bilateral agencies). Necessary expert advice and viewpoints from external sources can be appropriately injected in the process, but these should only play a supporting role. By engaging in such a process, the government will provide a signal to various stakeholders about the seriousness of the government's interest in developing a technology policy for this sector. The government is also appropriate initiator and coordinator of this national forum since there are many aspects of the clean-coal technology sector that are relevant to a range of "public goods" issues; at the same time, the development of a roadmap will require balancing the interest of various stakeholders.

We believe that the Planning Commission may be the best body to facilitate these discussions, given its relative 'neutrality' and its existing broad analytical base on power sector issues. The recently concluded Integrated Energy Policy process – a major energy policy exercise – has provided fresh impetus and a broad framework for energy policy discussions in the country. A technology roadmapping process could build on this momentum and serve as an important next step towards developing a robust approach to energy planning and policies in the country. The

Central Electricity Authority, with its deep technical strengths, could also play an important role in helping manage the roadmapping process. And organizations such as CIL, NTPC, and BHEL could play a crucial role in providing data and technical expertise for the roadmapping process. The monitoring and feasibility assessment institution, which was discussed above in section 8.2.3.1, would naturally play an important role in providing technology assessments and analysis for the roadmapping process.

At the same time, learning from clean-coal roadmapping experiences in other countries should also be useful (see section 5.2.2). Of particular importance will be their experiences with stakeholder involvement, and the integration of the output of the roadmapping exercise into the appropriate policy processes.

Finally, a successful roadmapping exercise will help all the stakeholders develop a shared understanding of the current state of affairs in the coal and coal-power sectors and an effective plan of action. This will go a long way in promoting the development of the coal-power sector in a manner commensurate with the challenges facing it.

9 Conclusion

Coal power has, in recent decades, become a key element of India's energy sector. As the country's energy and power needs continue to grow, underpinning the increasing pace of economic and social development, the importance of coal will remain undiminished for at least the next few decades. Yet, there are a number of challenges facing the coal-power sector; at the same time, there are several constraints that will affect its trajectory. At the same time, there is now a broad and evolving array of technology options for the coal power generation, unlike in the past when subcritical pulverized coal combustion was the dominant technology of choice. There are also varying concerns about the applicability of the new technologies for the Indian context. Given all this, it is important for India to engage in an in-depth analysis of technology issues as well as strategic planning to allow for appropriate development of the coal-power sector. There has already been some progress in this vein with the Planning Commission's recent Integrated Energy Policy report, but much more needs to be done.

This work is motivated by the above considerations, and has outlined the interlinkages between technology innovation and public policy, and highlighted the need for a technology roadmapping process as a tool to help determine appropriate policies in the sector. It then assesses relevant technology options in order to derive an illustrative technology roadmap and the requisite policy elements. Our analytical framework helps delineate the kinds of questions that need to be addressed, as well as our view of what the answers to some of these questions are.

However, this work should be viewed as a stepping-stone for a more comprehensive assessment that needs to be undertaken by the Indian government, preferably lead by the Planning Commission and with buy-in from policy-makers and key stakeholders. The key is to put in place appropriate processes for developing consensus-based solutions to the problems in the sector. These processes must be under the imprimatur of the government and with wide stakeholder participation, with the aim of developing a robust technology policy and a suitable domestic innovation strategy for the future of the country's coal-power sector.

References

Abbi, Y.P., 2003. "Technologies and policies to mitigate atmospheric pollution from thermal power plants in India." International Conference on Thermal Power Generation–Best Practices and Future Technologies, 13–15 October 2003, NTPC and USAID, p. 177–188.

Airy, A., 2003. "Rivals BHEL, Alstom in tech tie-up talks." The Financial Express, Net edition ed, November 27, 2003, New Delhi. See: http://www.financialexpress.com/

Alstom, 2005a. "Annual Report 2004-05." See: http://www.alstom.com

Alstom, 2005b. "Press Release: October 27, 2005. ALSTOM signs a partnership agreement with BHEL on large power plant boilers in India." October 27, 2005. See: http://www.alstom.com/pr_corp/2005/corp/29605.EN.php?languageId=EN&dir=/pr_corp/2005/corp/&idRubriqueCourante=15445

Anthony, E.J., 2003. "Atmospheric and Pressurized Fluidized Bed Technology." Clean Coal Technology Roadmap Workshop 1, March 20 - 21, 2003, Calgary, Alberta. See: http://www.nrcan.gc.ca/es/etb/cetc/combustion/cctrm/htmldocs/events_calgary_workshop_e.html

ATLAS, 2005. "ATLAS -- heat and power webpage." See: http://europa.eu.int/comm/energy_transport/atlas/htmlu/heat_and_power.html

Bachu, S., Gunter, W.D., Perkins, E.H., 1994. "Aquifer disposal of CO2: Hydrodynamic and mineral trapping." *Energy Conversion and Management* 35: 269-279.

Balachandra, K.S., Sharma, R.K., 2001. "Rationalizing Environmental Protection and Control Measures for New Power Plants." *Vidyut Bharti* 24.

Bendixen, K., 2003. "Experiences with Coal fired USC Boilers in Denmark." Power-Gen Europe, May 6-8 2003, Düsseldorf, Germany. See: http://www.bwe.dk/pdf/art-pge2003.pdf

Bhattacharyya, S.C., 1997. "An Estimation of Environmental Costs of Coal-based Thermal Power Generation in India." *International Journal of Energy Research* 21: 289-298.

BHEL, 2005a. "Annual Report 2004-05." See: http://www.bhel.com/bhel/images/pdf/AR0405.pdf

BHEL, 2005b. "Press Release 27-Oct-2005: BHEL becomes the first Indian company capable of manufacturing eco-friendly supercritical boilers." See: www.bhel.com

BHEL, 2005c. "Product: Steam Generators." See: http://www.bhel.com/bhel/product_services/range.php?rangeid=122&productid=96&categoryid=129

Bhuskute, K.G., Ambhaikar, N.M., 2002. "CFBC Technology: Environment friendly, More efficient, Suitable for wide spectrum of fuels & Cost effective." 2nd FICCI-TERI Global Conference "GREEN 2002: Agenda for Industry", February 7-8, 2002, New Delhi. See: http://www.cleantechindia.com/eicnew/green2002/CFBC_Final_Bhuskute.htm

Bonk, D., 2005. "Coal Gasification as Alternative Fuel for Glass Industry." See: http://www.gmic.org/Energy%20Page/Industrial%20Gasification%20Types%20and%20Peripherals.ppt

Booras, G., Holt, N., 2004. "Pulverized Coal and IGCC Plant Cost and Performance Estimates." Gasification Technologies 2004, October 3-6, 2004, Washington, D.C.

Bossel, U., 2003. "Well-to-Wheel Studies, Heating Values, and the Energy Conservation Principle." European Fuel Cell Forum, 29th October 2003. See: http://www.efcf.com/e/reports/E10.pdf

Bozzuto, C.R., Nsakala, N.y., Liljedahl, G.N., Palkes, M., Marion, J.L., Vogel, D., Gupta, J.C., Fugate, M., Guha, M.K., 2001. "Engineering Feasibility And Economics Of CO2 Capture On An Existing Coal-Fired Power Plant." Alstom Power Inc., Ohio Coal Development Office, and U.S. DOE NETL (June 2001). See: http://www.netl.doe.gov/coal/Carbon%20Sequestration/pubs/analysis/AlstomReport.pdf

BP, 2005. "BP Statistical Review of World Energy 2005." BP Corporation, (June 2005). See: http://www.bp.com/statisticalreview

BP, 2006. "BP Statistical Review of World Energy 2006." BP Corporation, (June 2006). See: http://www.bp.com/statisticalreview

Bradshaw, J., 2005. "Mapping world geological storage potential of CO2: Insights and implications." ETIP Seminar Series, Cambridge MA.

Bradshaw, J., Dance, T., 2004. "Mapping geological storage prospectivity of CO2 for the world's sedimentary basins and regional source to sink matching." 7th International Conference on Greenhouse Gas Control Technologies (GHGT-7), September 5–9, 2004, Vancouver, Canada.

Bryan, B.G., Laurens, R.M., Kramer, A., Hudziak, J., Lau, F.S., Chen, T.-P., Sonde, R.R., Dubey, D.K., 2005. "Flex-Fuel Test Facility: Evaluation of Fluidized-Bed Gasification for IGCC Power Production with High-Ash Indian Coal." 22nd Annual International Pittsburgh Coal Conference, Pittsburgh, U.S.

Buchanan, D.J., Brenkley, D., 1994. "Green Coal Mining." In: *Mining and its Environmental Impact*. Hester, R.E., Harrison, R.M. (eds.). The Royal Society of Chemistry, Cambridge, U.K.

CBIP, 1997. "Compendium of Thermal Power Stations in India." Central Board of Irrigation and Power, Government of India.

CEA, 1997. "Fourth National Power Plan 1997-2012." Central Electricity Authority, Government of India. See: http://www.cea.nic.in

CEA, 2000. "Sixteenth Electric Power Survey of India." Central Electricity Authority, Government of India.

CEA, 2003. "Report of the Committee to Recommend Next Higher Size of Coal Fired Thermal Power Stations." Central Electricity Authority, Ministry of Power. See: http://www.cea.nic.in

CEA, 2004a. "Draft Report on National Electricity Plan (Volume -I)." Central Electricity Authority, Government of India.

CEA, 2004b. "Performance Review of Thermal Power Stations 2002-03." Central Electricity Authority. See: http://www.cea.nic.in

CEA, 2005a. "Monthly Report on Broad Status of Thermal Power Projects in the Country." Central Electricity Authority. See: http://cea.nic.in/data/opt2_const_mon_th_index.htm

CEA, 2005b. "Performance Review of Thermal Power Stations 2003-04." Central Electricity Authority. See: http://www.cea.nic.in

CEA, 2005c. "Performance Review of Thermal Power Stations 2004-05." Central Electricity Authority. See: http://www.cea.nic.in

CEA, 2005d. "PREPARATION OF PRELIMINARY FEASIBILITY REPORTS (PFRs) under 50,000 MW Hydroelectric Initiative." Central Electricity Authority. See: http://www.cea.nic.in

CEA, 2005e. "Strategies for Ash Utilization." Central Electricity Authority. See: http://www.cea.nic.in/newweb/ash_utilization.htm

CEA, 2005f. "Technical Standard On Operation Norms For Coal/Lignite Fired Thermal Power Stations." Central Electricity Authority, Government of India.

CEA, 2006a. "All-India Electricity Statistics: General Review 2006." Central Electricity Authority. See: http://www.cea.nic.in

CEA, 2006b. "CO2 Baseline Database for the Indian Power Sector (Draft Version 1.0, October 4, 2006)." Central Electricity Authority. See: http://www.cea.nic.in

CEA, 2007a. "Power Scenario at a Glance (April 2007)." Central Electricity Authority. See: http://www.cea.nic.in

CEA, 2007b. "Report of the Working Group on Power for 11th Plan." CEA, Government of India. See: http://cea.nic.in/planning/WG%2021.3.07%20pdf/03%20Contents.pdf

CERA, 2005. "Worldwide Liquids Capacity Outlook To 2010— Tight Supply Or Excess Of Riches." Cambridge Energy Research Associates, Cambridge, MA. (June 2005). See: http://www.cera.com/attachment/view/0,2017,23649,00.pdf

CERC, 2000a. "Annual Report 1999-2000." Central Electricity Regulatory Commission. See: http://www.cercind.org

CERC, 2000b. "Proposal for purchase of power by PTC from HIRMA Mega Power Project and sale of such power on back to back basis to SEBs." September 26, 2000, Central Electricity Regulatory Commission. See: http://cercind.gov.in/pet24002609.html

CETC, 2005. "Canada's Clean Coal Technology Roadmap (CCTRM)." See: http://www.nrcan.gc.ca/es/etb/cetc/combustion/cctrm/htmldocs/cctrm_e.html

Chakravarty, S., 1974. "Report of the Fuel Policy Committee, India, 1974." Government of India.

Chand, S.K., 2005. "Can domestic coal continue to remain king?" TERI Newswire, 1-15 April 2005. See: http://www.teriin.org

Chand, S.K., Sarkar, S.K., 2006. "Demystifying Coal Security." Economic Times, April 14. See: http://economictimes.indiatimes.com/articleshow/1489625.cms

Chandler, W., Schaeffer, R., Dadi, Z., Shukla, P.R., Tudela, F., Davidson, O., Alpan-Atamer, S., 2002. "Climate change mitigation in developing countries: Brazil, China, India, Mexico, South Africa, and Turkey." Prepared for the Pew Center on Global Climate Change. See: http://www.pewclimate.org/global-warming-in-depth/all_reports/climate_change_mitigation

Chatterjee, K.K., 2003. "Adoption of UNFC System and its Application to Solid Mineral Commodities — Indian Experience." Practical Application of United Nations Framework Classification for Energy and Mineral Commodities, 24-25, April 2003, Moscow. See: http://www.unece.org/ie/se/pdfs/UNFC/UNFCpres.pdf

Chikkatur, A., 2005. "Making the Best Use of India's Coal Resources." *Economic and Political Weekly* 40: 5457-5461.

Chikkatur, A.P., Sagar, A.D., Abhyankar, N., Sreekumar, N., 2007a. "Tariff-based incentives for improving coal-power-plant efficiencies in India." *Energy Policy* 35: 3744-3758.

Chikkatur, A.P., Sagar, A.D., Sankar, T.L., 2007b. "Sustainable development of the Indian coal sector." *Energy*: Submitted.

CMIE, 1995. *India's Energy Sector*, July 1995 ed. Centre for Monitoring Indian Economy Pvt. Ltd., Bombay.

CMIE, 1999. *Energy*, May 2005 ed. Centre for Monitoring Indian Economy Pvt. Ltd., Bombay.

CMIE, 2002. *Energy*, May 2005 ed. Centre for Monitoring Indian Economy Pvt. Ltd., Bombay.

CMIE, 2005. *Energy*, May 2005 ed. Centre for Monitoring Indian Economy Pvt. Ltd., Bombay.

CMPDIL, 2001. "Millennium Coal Vision." National Seminar on Coal, December 20-21, 2001, Central Mine Planning and Design Institute Limited (CMPDIL), Ranchi.

CMPDIL, 2004. "Highlights of Research: COAL S&T PROGRAMME." Central Mine Planning and Design Institute Limited (CMPDIL), Ranchi. See: http://scienceandtech.cmpdi.co.in/Highlights.htm

Cortright, J., 2001. "New Growth Theory,Technology and Learning: A Practitioner's Guide." U.S. Economic Development Administration. See: http://www.eda.gov/PDF/1G3LR_7_cortright.pdf

CPCB, 2000a. "Annual Report 1999-2000." Central Pollution Control Board. See: http://www.cpcb.nic.in/annual_report1999-2000.htm

CPCB, 2000b. "Parivesh -- Clean Coal Initiatives." Central Pollution Control Board, Ministry of Environment and Forests. See: http://envfor.nic.in/cpcb/newsletter/coal/contents.html

CPCB, 2001. "Annual Report 2000-2001." Central Pollution Control Board. See: http://www.cpcb.nic.in/annual_report2000-01.htm

CPCB, 2005. "Thermal Power Plant: Environmental Standards." See: http://www.cpcb.nic.in/standard63.htm

CWPC, 1951. "Public Electricity Supply: All India Statistics, 1950." Central Water & Power Commission (Power Wing), Ministry of Natural Resources and Scientific Research, Government of India.

CWPC, 1955. "Planning for Power Development in India." Central Water & Power Commission (Power Wing), Ministry of Irrigation and Power, Government of India.

Dalal, G.G., 1999. "Ash management upstream and downstream -- overview." in: Varma, C.V.J., Lal, P.K. (Eds.), Quantification of Environmental Impacts of Large Power Projects, February 25-26, 1999, Central Board of Irrigation and Power, Bhopal, M.P., India.

Datta, M., 1961. "Census of India 1961: Electricity Supply in India and an Analysis of Power Development during the two Five Year Plan Periods (1951-56 & 1956-61)." Ministry of Home Affairs.

David, J., Herzog, H., 2000. "The Cost of Carbon Capture." Fifth International Conference on Greenhouse Gas Control Technologies, August 13 -16, 2000, IEA, Cairns, Australia. See: http://sequestration.mit.edu/pdf/David_and_Herzog.pdf

Dayal, H.V., 1980. "Analysis of the Power Subsector." In: *Energy Policy for India*. Pachauri, R.K. (ed.). Macmillian Company of India, Delhi.

Deffeyes, K.S., 2001. *Hubbert's Peak: The Impending World Oil Shortage*. Princeton University Press, Princeton, NJ.

Dennis, C., 2006. "Promises to clean up industry fail to convince." *Nature* 439: 253.

Deo Sharma, S.C., 2004. "Coal-fired Power Plant Heat Rate and Efficiency Improvement in India." Workshop on Near-Term Options to Reduce CO2 Emissions from the Electric Power Generation Sector in APEC Economies, February 2004, Asia Pacific Economic Cooperation (APEC), Queensland, Australia. See: http://www.iea.org/dbtw-wpd/Textbase/work/2004/zets/apec/presentations/sharma.pdf

Department of Fertilizers, 2004. "Annual Report 2003-04." Ministry of Chemicals and Fertilizers, Government of India. See: http://fert.nic.in/annualreport/annualreport.asp

Desai, A., 1980. "The origin and direction of industrial R&D in India." *Research Policy* 9: 74-96.

DGH, 2004. "Petroleum Exploration and Production Activities in India, 2003-2004." Directorate General of Hydrocarbons, Ministry of Petroleum and Natural Gas. See: http://www.dghindia.org

Dhar, B., 1988. "State Regulation of Foreign Capital in India." IDPAD project on Impact of MNCs in India's Position in International Division of Labour. See: http://isid.org.in/pdf/statreg.pdf

Dillon, D.J., Panesar, R.S., Wall, R.A., Allam, R.J., White, V., Gibbins, J., Haines, M.R., 2004. "Oxy-Combustion Processes For CO2 Capture from Advanced Supercritical PF and NGCC Power Plant." 7th International Conference on Greenhouse Gas Control Technologies (GHGT-7), September 5–9, 2004, Vancouver, Canada.

Dinar, A., Mendelsohn, R., Evenson, R., Parikh, J., Sanghi, A., Kumar, K., McKinsey, J., Lonergan, S., 1998. "Measuring the impact of climate change on Indian agriculture,Volume 1." World Bank, Washington, D.C.

Divan, S., Rosencranz, A., 2001. *Environmental Law and Policy in India*. Oxford University Press, New Delhi.

Dooley, J.J., Friedmann, S.J., 2004. "A Regionally Disaggregated Global Accounting of CO2 Storage Capacity: Data and Assumptions." See: http://eed.llnl.gov/co2/pdf/GlobalCO2CapcityEstimate.pdf

DST, 2005. "Research and Development Statistics at a Glance 2004-05." Department of Science and Technology, Government of India. See: http://www.nstmis-dst.org/PublicationRD2005.htm

DTI, 1998. "GASIFICATION OF SOLID AND LIQUID FUELS FOR POWER GENERATION." Department of Trade and Industry (DTI), U.K. See: http://www.dti.gov.uk/energy/coal/cfft/cct/pub/tsr008.pdf

DTI, 1999. "Supercritical Steam Cycles for Power Generation Applications." Department of Trade and Industry (DTI), U.K. See: http://www.berr.gov.uk/files/file18320.pdf

DTI, 2000a. "FLUIDISED BED COMBUSTION SYSTEMS FOR POWER GENERATION AND OTHER INDUSTRIAL APPLICATIONS." Department of Trade and Industry (DTI), U.K. See: http://www.dti.gov.uk/energy/coal/cfft/cct/pub/tsr011.pdf

DTI, 2000b. "Review of technology requirements of the coal preparation sector in India." Department of Trade and Industry (DTI), U.K. See: http://www.berr.gov.uk/files/file20013.pdf

DTI, 2001. "Coal Preparation." Department of Trade and Industry (DTI), U.K. See: http://www.berr.gov.uk/files/file19296.pdf

DTI, 2002. "Review of status of advanced materials for power generation." Department of Trade and Industry (DTI), U.K. See: http://www.berr.gov.uk/files/file20906.pdf

DTI, 2004a. "Promoting commercially viable UCG in China." Department of Trade and Industry (DTI), U.K. See: http://www.berr.gov.uk/files/file20060.pdf

DTI, 2004b. "Review of the feasibility of underground coal gasification in the UK." Department of Trade and Industry (DTI), U.K. See: http://www.berr.gov.uk/files/file19143.pdf

Dubash, N., 2005. "The New Regulatory Politics of Electricity in India: Independent, Embedded or Transcendent?" Workshop on "The Politics of Necessity", September 9-10, 2005, Oxford. See: www.cgdev.org/doc/event%20docs/Dubash_Regulatory%20Politics%20of%20Electricity.pdf

Dubash, N.K. (Ed.), 2002. *Power Politics: Equity and Environment in Electricity Reforms*. World Resources Institute, Washington D.C.

Dubash, N.K., D. Narasimha Rao, 2007. *The Practice and Politics of Regulation: Regulatory Governance in Indian Electricity*. Macmillan India.

Dubash, N.K., Rajan, S.C., 2001. "Power Politics: Process of Power Sector Reforms in India." *Economic and Political Weekly* 36: 3367-3390.

Dubash, N.K., Singh, D., 2005a. "Alternating Currents: Introduction to an International Review of Electricity Restructuring." *Economic and Political Weekly* 40: 5242-5248.

Dubash, N.K., Singh, D., 2005b. "Of Rocks and Hard Places: A Critical Overview of Recent Global Experience with Electricity Restructuring." *Economic and Political Weekly* 40: 5249-5259.

Dutt, R.C., 1990. *State Enterprises in a Developing Country*. Abhinav Publications, New Delhi.

Dwivedi, O.P., Kishore, B., 1982. "India'a Environmental Policies: A Review." In: *Environmental Policy in India*. Singh, S. (ed.). Indian Institute of Public Administration, New Delhi.

EIA, 2000. "Energy Policy Act Transportation Rate Study: Final Report on Coal Transportation." Energy Information Agency, Office of Coal, Nuclear, Electric and Alternate Fuels, U.S. Department of Energy, Washington D.C. (October 2000). See: ftp://ftp.eia.doe.gov/pub/pdf/coal.nuclear/059700.pdf

EIA, 2001. "Electric Power Annual 2000." Energy Information Agency, U.S. Department of Energy

EIA, 2006. "International Energy Outlook 2006." Energy Information Agency, Department of Energy, U.S. See: http://www.eia.doe.gov/oiaf/ieo/index.html

EPRI, 1999. "Enhanced Oil Recovery Scoping Study." EPRI, Palo Alto, CA. See: http://www.energy.ca.gov/process/pubs/electrotech_opps_tr113836.pdf

EPRI, 2003. "Electricity Technology Roadmap: 2003 Summary and Synthesis." Electric Power Research Institute, Inc., Palo Alto, CA. See: http://www.epri.com/roadmap/viewpdfs.asp

EPRI, Parsons, 2000. "Evaluation of Innovative Fossil Fuel Power Plants with CO2 removal." Office of Fossil Energy, U.S. DOE and U.S. NETL See: http://www.netl.doe.gov/technologies/coalpower/gasification/pubs/pdf/EpriReport.PDF

Farzan, H., Vecci, S.J., Châtel-Pélage, F., Pranda, P., Bose, A.C., 2005. "Pilot-Scale Evaluation of Coal Combustion in an Oxygen-Enriched Recycled Flue Gas." The 22nd International Pittsburgh Coal Conference, September 12-15, 2005, Pittsburgh, PA.

Fernandes, D., Saldanha, L., 2000. "Deep Politics, Liberalisation and Corruption: The Mangalore Power Company Controversy." *Law, Social Justice and Global Development*.

FPC, 1974. "Report of the Fuel Policy Committee, India, 1974." Government of India.

Frankland, S.C., 2000. "Review of technology requirements of the coal preparation sector in India." DTI

Friedmann, S.J., 2005. "Underground Coal Gasificiation in the USA and Abroad." Senate Foreign Relations Committee Hearings, Washington. (November 14th, 2005).

GAO, 1996. "Changes in electricity-related R&D funding." U.S. General Accounting Office, Washington, D.C. See: www.gao.gov/archive/1996/rc96203.pdf

Garcia, M.L., Bray, O.H., 1997. "Fundamentals of Technology Roadmapping." Strategic Business Development Department, Sandia National Laboratories, See: http://www.sandia.gov/PHMCOE/pdf/Sandia%27sFundamentalsofTech.pdf

Garg, A., Bhattacharya, S., Shukla, P.R., Dadhwal, V.K., 2001a. "Regional and sectoral assessment of greenhouse gas emissions in India." *Atmospheric Environment* 35: 2679-2695.

Garg, A., Menon-Choudhary, D., Kapshe, M., Shukla, P.R., 2004. "Carbon Dioxide Capture and Storage Potential in India." in: E.S.Rubin, D.W.Keith, C.F.Gilboy (Eds.), 7th International Conference on Greenhouse Gas Control Technologies (GHGT-7), Vancouver, Canada. See: http://uregina.ca/ghgt7/PDF/papers/peer/343.pdf

Garg, A., Shukla, P.R., Bhattacharya, S., Dadhwal, V.K., 2001b. "Sub-region (district) and sector level SO_2 and NO_x emissions for India: assessment of inventories and mitigation flexibility." *Atmospheric Environment* 35: 703-713.

Ghosh, D., 2005. "Assessment of Advanced Coal-Based Electricity Generation Technology Options for India: Potential Learning from U.S. Experiences." Belfer Center for Science and International Affairs, Kennedy School of Government, Cambridge. See: http://bcsia.ksg.harvard.edu/?program=STPP

GoI, 1948a. "The Electricity Supply Act, 1948." Government of India.

GoI, 1948b. "Industrial Policy Resolution." Government of India. See: http://www.laghu-udyog.com/policies/iip.htm

GoI, 1956. "Industrial Policy Resolution." Government of India. See: http://www.laghu-udyog.com/policies/iip.htm

Goldemberg, J., Johansson, T.B., Reddy, A.K.N., Williams, R.H., 1988. *Energy for a Sustainable World*. Wiley Eastern Limited, New Delhi.

Gopalakrishnan, A., 2002. "Evolution of the Indian Nuclear Power Program." *Annual Review of Energy and the Environment* 27: 369-395.

Gopalakrishnan, A., 2005. "Indo-US Nuclear Cooperation: A Non-starter?" *Economic and Political Weekly*.

Gopinath, V.K., Balagurunathan, S., Gopalakrishnan, V., 2002. "Advanced Clean Coal Technology - Perspectives for India." See: www.igeos.pl/doc/coaldialogue/WEC-Coal_Slides.ppt

Govil, K.K., 1998. *Electricity Generation -- Policy, Technology and Economy*. Venus Publishing House, New Delhi.

Gupta, A.B., 1979. *Whither Coal*. Vision Books Private Limited, New Delhi.

Gupta, J., Vlasblom, J., Koreze, C., 2001. "An Asian Dilemma. Modernising the electricity sector in China and India in the context of rapid economic growth and concern from climate change." Free University, Institute for Environmental Studies, Amsterdam.

Gupta, M., Zanganeh, K.E., Tan, Y., Pearson, B., 2005. "Oxy-fuel Combustion With and Without Carbon Capture: A Techno-Economic Assessment and Future Prospects." 22nd International Pittsburgh Coal Conference, September 2005, Pittsburgh, PA.

Gyllenspetz, J., Parker, K., Sanyal, A., Roy, C., 1998. "Enhanced particulate collection from Indian coal fired power plants." American Power Conference, held in., April 13 -16,1998, Baltimore. USA.

Henderson, P.D., 1975. *India, The Energy Sector*. Oxford University Press for World Bank, New York.

Higman, C., Sharma, R.K., 1998. "Gasification - an Indian Perspective." “Gasification, The Gateway to a Cleaner Future” -- 3rd European Conference on Gasification, Dresden, Germany.

Holt, N., 2004a. "Coal–based IGCC Plants: Recent Operating Experience and Lessons Learned." Gasification Technologies Conference, October 4-6, 2004, Washington, DC.

Holt, N., 2004b. "Gasification Process Selection- Trade-offs and Ironies." Gasification Technologies Conference, October 4-6, 2004, Washington, DC.

Holt, N., 2006. "IGCC & Gasification for a changing marketplace." MIT Carbon Sequestration Forum VII, 31 October - 1 November 2006, Cambridge, MA.

IAEA, UNDESA, IEA, Eurostat, Agency, E.E., 2005. "Energy Indicators for Sustainable Development: Guidelines and Methodologies." International Atomic Energy Agency, Vienna. See: http://www-pub.iaea.org/MTCD/publications/PDF/Pub1222_web.pdf

IEA, 1998. "Regional trends in energy-efficient coal-fired, power generation technologies." Paris, France.

IEA, 2002a. "Coal in the Energy Supply of India." International Energy Agency -- Coal Industry Advisory Board

IEA, 2002b. "World Energy Outlook 2002." International Energy Agency

IEA, 2004a. "Energy Balances of Non-OECD Countries 2001- 2002 (2004 Edition)." International Energy Agency

IEA, 2004b. "Energy Balances of OECD Countries 2001- 2002 (2004 Edition)." International Energy Agency

IEA, 2004c. "Key World Energy Statistics 2004." International Energy Agency See: http://www.iea.org/dbtw-wpd/Textbase/nppdf/free/2004/keyworld2004.pdf

IEA, 2004d. "Profiles: Utilisation of CFBC and IGCC residues." (December 2004). See: http://www.iea-coal.co.uk/templates/ieaccc/report_detail.asp?LogDocId=81142&PageId=323

IEA, 2004e. "World Energy Outlook 2004." International Energy Agency

IEA, 2005a. "Clean coal technologies - home page." See: http://www.iea-coal.org.uk/site/ieaccc/home

IEA, 2005b. "Roadmapping Coal's Future." International Energy Agency, Paris. See: http://www.iea.org/textbase/papers/2005/roadmapping.pdf

IEA, 2006a. "Coal Information 2006." International Energy Agency

IEA, 2006b. "Energy Balances of Non-OECD Countries 2003-2004 (2006 Edition)." International Energy Agency

India Infoline, 2000. "Leader Speak with Mr Jagadip Narayan Singh." India Infoline. See: http://www.indiainfoline.com/view/070200.html

Industry Canada, 2000. "Technology Roadmapping: A strategy for success." Industry Canada, See: http://strategis.ic.gc.ca/epic/internet/intrm-crt.nsf/vwapj/TRMguide_e.pdf/$FILE/TRMguide_e.pdf

IPCC, 2001. "Summary for Policymakers." In: *Climate Change 2001. Synthesis report*. Watson, R.T., Core Writing Team (eds.). Intergovernmental Panel on Climate Change. See: http://www.ipcc.ch/pub/un/syreng/spm.pdf

IPCC, 2005. "IPCC Special Report on Carbon Dioxide Capture and Storage: Technical Summary." See: http://www.ipcc.ch/activity/srccs/index.htm

IPCC, 2007. "Summary for Policymakers of the Synthesis Report of the IPCC Fourth Assessment Report." Intergovernmental Panel on Climate Change

Jain, S.K., Roy, D.N., 1999. "Estimation of mercury emission at a coal fired power plant: A methodology." in: Varma, C.V.J., Lal, P.K. (Eds.), Seminar on Energy and Environment in the context of Thermal Power Generation, Council of Power Utilities, Lucknow, India.

Jala, S., Goya, D., 2006. "Fly ash as a soil ameliorant for improving crop production—a review." *Bioresource Technology* 97: 1136-1147.

Jeyakumar, V., 2004. "Financing of Power Projects in India." 19th World Energy Congress, September 5-9, 2004, Sydney, Australia.

Joshi, V., Little, I.M.D., 1996. *India's Economic Reforms, 1991-2001*. Oxford University Press, Oxford.

Kanchan, P.K., 2006. "Coal Beneficiation (CMDPIL)." Third US-India Coal Working Group Meeting, April 4-5, 2006, U.S. DOE, Delhi, India. See: http://www.fossil.energy.gov/international/Publications/cwg_april06_cb_cmpdi.pdf

Kandlikar, M., Sagar, A., 1999. "Climate change research and analysis in India: an integrated assessment of a South-North divide." *Global Environmental Change* 9: 119-138.

Kashiwagi, T., Ono, H., Watari, R., Sekine, I., 2004. "The New Direction of Japanese Energy Policy and the Role of Gasification." 2004 Gasification Technologies Conference, October 3-6, 2004, Washington, D.C. See: http://www.gasification.org/

Katz, J., 1984. "Domestic technological innovations and dynamic comparative advantage." *Journal of Development Economics* 16: 13-37.

Kavidass, S., Anderson, G.L., G.S. Norton, J., 1999. "IR-CFB Repowering: A Cost-Effective Option for Older PC-Fired Boilers." POWER-GEN International 1999, November 30-December 2, 1999, New Orleans, Louisiana, U.S.A.

Kavidass, S., Anderson, G.L., G.S. Norton, J., 2000. "Why Build a Circulating Fluidized Bed Boiler to Generate Steam and Electric Power." POWER-GEN Asia 2000, September 20-22, 2000, Bangkok, Thailand.

Khan, S.R., Wayland, R.J., Schmidt, L.J., 2005. "Environmental Impact Comparisons: IGCC vs. PC Plants." 22nd Annual International Pittsburgh Coal Conference, Pittsburgh, U.S.

Khanna, M., Zilberman, D., 1999. "Barriers to Energy-Efficiency in Electricity Generation in India." *Energy Journal* 20: 25.

Khator, R., 1991. *Environment, Development and Politics in India*. University Press of America, Inc., New York.

Kitto, J.B., 1996. "Developments in Pulverized Coal-Fired Boiler Technology." Missouri Valley Electric Association Engineering Conference, April 10-12, 1996, Kansas City, Missouri.

Kline, S.J., Rosenberg, N., 1986. "An Overview of Innovation." In: *The Positive Sum Strategy: Harnessing Technology for Economic Growth*. Landau, R., Rosenberg, N. (eds.). National Academy Press, Washington, D.C. See: http://newton.nap.edu/catalog/612.html

Kolar, A.K., 2006. "Advanced Coal Technologies for India." National Conference on Advances in Energy Research, Draft Keynote Lecture -- unpublished, IIT-Bombay, Mumbai, India.

Krishna, M.G., 1980. "Indian Coal Industry: Past, Present and Future." In: *Energy Policy for India*. Pachauri, R.K. (ed.). Macmillian Company of India, Delhi.

Kuehn, S.E., 1996. "Power for the Industrial Age: A brief history of boilers." *Power Engineering* 100: 5-19.

Kumar, M., 2005. "NTPC sanctions 2000 MW project to dubious Russian firm." The Tribune, Online Edition ed, February 25, 2005, Chandigarh. See: http://www.tribuneindia.com/2005/20050225/biz.htm#3

Kwant, K.W., Knoef, H., 2004. "Status of Biomass Gasification in the Countries Participating in the IEA Bioenergy, Task 33: Biomass Gasification and EU Gasnet." IEA Bioenergy and EU Gasnet (October 2004). See: http://www.gastechnology.org/webroot/app/xn/xd.aspx?it=enweb&xd=iea/countries.xml

Lako, P., 2004. "Coal-fired Power technologies: Coal-fired power options on the brink of climate policies." ECN Beleidsstudies
ECN Policy Studies See: http://www.ecn.nl/docs/library/report/2004/c04076.pdf

Lall, S., 1987. *Learning to Industrialize: The Acquisition of Technological Capacity by India*. Macmillan Press, London.

Lookman, A.A., Rubin, E.S., 1998. "Barriers to adopting least-cost particulate control strategies for Indian power plants." *Energy Policy* 26: 1053-1063.

Lovins, A.B., 1977. *Soft Energy Paths*. Harper Colophon Books, Harper & Row Publishers, New York.

Marion, J.L., Bozzuto, C.R., Nsakala, N.y., Liljedahl, G.N., Andrus, H.E., Chamberland, R.P., 2003. "Greenhouse Gas Emissions Control By Oxygen Firing In Circulating Fluidized Bed Boilers: Phase 1 -- A preliminary systems evaluation." Alstom Power Inc. and U.S. D.O.E. NETL (MAY 15, 2003). See: http://www.netl.doe.gov/coal/Carbon%20Sequestration/pubs/analysis/41146_R01_Volume%20I.pdf

Marland, G., Boden, T.A., Andres, R.J., 2005. "Global, Regional, and National CO2 Emissions. In Trends: A Compendium of Data on Global Change." December 2005, Carbon Dioxide Information Analysis Center, Oak Ridge National Laboratory, U.S. Department of Energy, Oak Ridge, Tenn., U.S.A. See: http://cdiac.ornl.gov/trends/emis/em_cont.htm

Marland, G., Boden, T.A., Andres, R.J., 2007. "Global, Regional, and National CO2 Emissions. In Trends: A Compendium of Data on Global Change." September 2007, Carbon Dioxide Information Analysis Center, Oak Ridge National Laboratory, U.S. Department of Energy, Oak Ridge, Tenn., U.S.A. See: http://cdiac.ornl.gov/trends/emis/em_cont.htm

Masto, R.E., Ram, L.C., Selvi, V.A., Jha, S.K., Srivastava, N.K., 2007. "Soil contamination and human health risks in coal mining environs." in: Singh, G., Laurence, D., Lahiri-Dutt, K. (Eds.), 1st International Conference on Managing the Social and Environmental Consequences of Coal Mining in India, November 19-21, 2007, Indian School of Mines University, Dhanbad, New Delhi.

Matsuno, Y., Tsutsumi, A., Yoshida, K., Parikh, J.K., Reddy, B.S., Banerjee, R., Koundinya, S., 1996. "DSM survey in India: Awareness, barriers and implementability." *Energy* 21: 955-966.

McKinlay, A.F., Allen, S.G., Cox, R., Dimbylow, P.J., Mann, S.M., Muirhead, C.R., Saunders, R.D., Sienkiewicz, Z.J., Stather, J.W., Wainwright, P.R., 2004. "Review of the Scientific Evidence for Limiting Exposure to Electromagnetic Fields (0–300 GHz)." *Documents of the NRPB* 15.

Mehta, A., 2000. *Power Play: A Study of the Enron Project*. Orient Longman, New Delhi.

Merrick, D., 1984. *Coal Combustion and Conversion Technology*. Macmillan Publishers Ltd., London.

Miller, B.G., 2005. *Coal Energy Systems*. Elsevier Academic Press, Boston.

Ministry of Coal, 2004. "Annual Report 2003-04." Ministry of Coal, Government of India. See: http://coal.nic.in/

Ministry of Coal, 2005a. "Report (Part-I) of the Expert Committee on Road Map for Coal Sector Reforms." Ministry of Coal, Government of India. See: http://www.coal.nic.in/expertreport.pdf

Ministry of Coal, 2005b. "Vision Coal 2025 (Draft)." Ministry of Coal, Government of India.

Ministry of Coal, 2006. "Annual Report 2005-06." Ministry of Coal, Government of India. See: http://coal.nic.in/

Ministry of Finance, 2007. "Economic Survey 2006-07." Ministry of Finance, Government of India. See: http://indiabudget.nic.in/es2006-07/esmain.htm

Ministry of Power, 2001. "Blueprint for Power Sector Development." Ministry of Power, Government of India. See: http://powermin.nic.in/

Ministry of Power, 2003. "Report of the Committee on "Financing of Power Sector during X and XI Plans"." Ministry of Power, Government of India. See: http://powermin.nic.in/

Ministry of Power, 2004. "Annual Report 2003-04." Ministry of Power, Government of India. See: http://powermin.nic.in/

Ministry of Power, 2005. "Renovation & Modernization For Thermal Power Stations." See: http://powermin.nic.in/generation/renovation_modernization_thermal.htm

Ministry of Power, 2006. "Annual Report 2005-06." Ministry of Power, Government of India. See: http://powermin.nic.in/

MIT, 2007. "The Future of Coal: Options for a carbon-constrained world." Massachusetts Institute of Technology, Cambridge, MA. See: http://web.mit.edu/coal/The_Future_of_Coal.pdf

MoEF, 1999. "Fly ash Notification." Ministry of Environment and Forests. See: http://www.envfor.nic.in/legis/hsm/so763(e).pdf

MoEF, 2004. "India's Initial National Communication to the United Nations Framework Convention on Climate Change." Ministry of Environment and Forests, Government of India. See: http://unfccc.int/resource/docs/natc/indnc1.pdf

MOSPI, 2005. "Energy Statistics 2004-05." Ministry of Statistics and Programme Implementation. See: http://mospi.nic.in/energy_stat.htm

Mukherjee, A.B., Zevenhoven, R., 2006. "Mercury in coal ash and its fate in the Indian subcontinent: A synoptic review." *Science of the Total Environment* 368: 384–392.

Najmabadi, F., Lall, S., 1995. *Developing Industrial Technology: Lessons for Policy and Practice*. The World Bank, Washington, D.C.

Nandakumar, K., 2006. "UCG and Power Generation: BHEL's role." Third US-India Coal Working Group Meeting, April 4-5, 2006, U.S. DOE, Delhi, India. See: http://www.fossil.energy.gov/international/Publications/cwg_april06_ucg_bhel.pdf

Narain, S., 2005. "The new dirty deal." Down to Earth, September 15, 2005. See: http://www.downtoearth.org.in/editor.asp?foldername=20050915&filename=Editor&sec_id=2&sid=1

National Planning Committee, 1949. *Power and Fuel -- Report of the Sub-Committee*. Vora & Co. Publishers Ltd., Bombay.

National Planning Committee, 1988. *Report of the National Planning Committee 1938*. Indian Institute of Applied Political Research, New Delhi.

NCST, 1974. "Report of the Fuel and Power Sector." National Committee on Science and Technology, Government of India.

NEERI, 2003. "Draft Report on Guidance Manual: Environmental Impact Assessment of Thermal Power Projects." Ministry of Environment and Forests.

NETL, 2000a. "Air blown KRW Gasifier IGCC Base Cases." Process Engineering Division, U.S. D.O.E. NETL, See: http://www.netl.doe.gov/technologies/coalpower/gasification/system/krw3x_20.pdf

NETL, 2000b. "British Gas/Lurgi Gasifier IGCC Base Cases." Process Engineering Division, U.S. D.O.E. NETL, See: http://www.netl.doe.gov/technologies/coal_and_power_systems/gasification/system/bgl3x_20.pdf

NETL, 2004a. "Clean Coal Technology Roadmap: Background Information." Laboratory, N.E.T., Office of Fossil Energy, U.S. Department of Energy. See: http://www.netl.doe.gov/technologies/coalpower/cctc/ccpi/pubs/CCT-Roadmap-Background.pdf

NETL, 2004b. "World Gasification Database." See: http://www.netl.doe.gov/coal/gasification/database/database.html

NETL, 2005. "Gasfication." 05/24/2005. See: http://www.netl.doe.gov/coal/gasification/

Nexant, 2003. "Feasibility Study of a Coal-based IGCC Power Plant in India. Topical Report for Phase A: Comparison of various IGCC and other advanced technologies (Submitted to USAID/India)." Nexant Corporation,

NRC, 1995. *Coal: Energy for the Future*. National Academy Press, Washington, D.C.

NSB, 2006. "Science and Engineering Indicators 2006 (Two volumes)." National Science Board, National Science Foundation, Arlington, VA.

NTPC, 1999. Performance Optimizer, October 1999.

NTPC, 2003. "Annual Report for the Year 2002-03."

NTPC, 2004. "Emission Standards -- Presentation at the March 2004 EPA-NTPC discussion on power plant emissions."

Open Europe, 2006. "The high price of hot air: Why the EU Emissions Trading Scheme is an environmental and economic failure." See: http://www.openeurope.org.uk/research/ets.pdf

Ottinger, R.L., Wooley, D.R., Robinson, N.A., Hodas, D.R., Babb, S.E., 1990. *Environmental Costs of Electricity*. Oceana Publications, Inc., New York.

Paap, J.E., 2006. "Customer Focused Technology Planning." Paap Associates See: http://www.jaypaap.com/articles/ACF6F14.pdf

Palkes, M., Waryasz, R.E., Liljedahl, G.N., 2004. "Economics and Feasibility of Rankine Cycle Improvements for Coal Fired Power Plants." Alstom Power Inc., NETL. See: http://www.osti.gov/bridge/servlets/purl/835217-W5ZD6s/native/835217.pdf

Pande, V.G., 1980. "Towards an Increased Concern with Energy: Research and Development in India." In: *Energy Policy for India*. Pachauri, R.K. (ed.). Macmillian Company of India, Delhi.

Parikh, K., 2001. "Thinking through the Enron Issue." *Economic and Political Weekly*.

Parsons, 2002. "Evaluation of Fossil Fuel Power Plants with CO2 recovery." U.S. D.O.E. NETL and Parsons Infrastructure and Technology Group See: http://www.netl.doe.gov/technologies/carbon_seq/refshelf/analysis/Evaluation_of_Fossil_Fuel_Power_Plants_with_CO2_Recovery.pdf

Paul, I., 1999. "Supercritical Coal Fired Power Plants: A Technology Being Successfully Deployed in Developing Countries." World Bank See: http://www.worldbank.org

PFC, 2005a. "Annual Report 2004-05." Power Finance Corporation. See: http://www.pfcindia.com/ann_rpt0405.pdf

PFC, 2005b. "Report on the Performance of the State Power Utilities for the years 2001-02 to 2003-04." Power Finance Corporation. See: http://www.pfcindia.com/seb_report.pdf

Phadke, A., 2001. "Questionable Economics of LNG-Based Power Generation: Need for Rigorous Analysis." *Economic and Political Weekly* 36: 1718.

PIB, 2001. "COAL RESERVES IN THE COUNTRY." Press Information Bureau, Government of India. See: http://pib.nic.in/archieve/lreleng/lyr2001/rmar2001/r18032001.html

PIB, 2004. "ONGC SIGNS MOU WITH RUSSIAN INSTITUTE FOR UNDERGROUND COAL GASIFICATION." Press Information Bureau, Government of India. See: http://pib.nic.in/release/release.asp?relid=5130

Planning Commission, 1952. "First Five-Year Plan." Government of India. See: http://planningcommission.nic.in/plans/planrel/fiveyr/1st/1planch26.html

Planning Commission, 1999. "Annual Report on the Working of State Electricity Boards & Electricity Departments (April 1999)." Planning Commission, Government of India. See: http://planningcommission.nic.in/

Planning Commission, 2000. "Annual Report on the Working of State Electricity Boards & Electricity Departments (April 2000)." Planning Commission, Government of India. See: http://planningcommission.nic.in/

Planning Commission, 2001. "Annual Report on the Working of State Electricity Boards & Electricity Departments (June 2001)." Planning Commission, Government of India. See: http://planningcommission.nic.in/

Planning Commission, 2002a. "Annual Report (2001-02) on the Working of State Electricity Boards & Electricity Departments (May 2002)." Planning Commission, Government of India. See: http://planningcommission.nic.in/

Planning Commission, 2002b. "Tenth Five-Year Plan." Planning Commission, Government of India. See: http://planningcommission.nic.in/

Planning Commission, 2005. "Mid-Term Assessment of the Tenth Five Year Plan." Planning Commission, Government of India. See: http://planningcommission.nic.in/

Planning Commission, 2006. "Integrated Energy Policy: Report of the Expert Committee." Planning Commission, Government of India. See: http://planningcommission.nic.in/reports/genrep/rep_intengy.pdf

Point Carbon, 2006a. "Carbon 2006: Towards a truly global market." (February 28, 2006). See: http://www.pointcarbon.com/getfile.php/fileelement_74094/Carbon_2006_final_print.pdf

Point Carbon, 2006b. "Carbon Market Europe, July 2006." (July 21, 2006). See: http://www.climatefocus.com/content/news/news_documents/PC_Europe_21_Jul_06.pdf

Power Economy Committee, 1973. "Report of the Study Group - I." Ministry of Irrigation and Power, Government of India.

Power Technology, 2005. "LAGISZA POWER PLANT SUPERCRITICAL CIRCULATING FLUIDISED BED, POLAND." SPG Media Limited. See: http://www.power-technology.com/projects/lagisza/

PowerClean, 2004. " Fossil Fuel Power Generation: State-Of-The-Art." PowerClean R, D&D Thematic Network (30th July 2004). See: http://www.cleanpowernet.net/state_art.pdf

Prasad, N.B., 1979. "Report of the Working Group on Energy Policy." Planning Commission, Government of India.

Prayas, 2001. "Godbole Committee on Enron Project: Expose and Way Out." *Economic and Political Weekly*.

Prayas, 2005. "Restarting Dabhol: Who Will Bear the Cost? And Why?" *Economic and Political Weekly*.

Purkayastha, P., 2001. "Power Sector Policies and New Electricity Bill: from Crisis to Disaster." *Economic and Political Weekly*.

Purkayastha, P., 2005. "BHEL Disinvestments -- An attack on the power sector." *People's Democracy (Weekly Organ of the Community Party of India (Marxist)* 29.

Qureshi, N., 2001. "Technology Scan on IGCC." National Thermal Power Corporation (NTPC),

Rajesh, N., Shukla, P.R., Kapshe, M., Garg, A., Rana, A., 2003. "Analysis of Long-Term Energy and Carbon Emission Scenarios for India." *Mitigation and Adaptation Strategies for Global Change* 8: 53-69.

Ramanna, R., 1980. "Inevitability of Atomic Energy in India's Power Programme." In: *Energy Policy for India*. Pachauri, R.K. (ed.). Macmillian Company of India, Delhi.

Ramesh, M., 2004. "No takers yet for BHEL supercritical boilers." The Hindu Business Line, Internet edition ed, April 6, 2004, Tiruchi. See: http://www.thehindubusinessline.com

Ramesh, M., 2005. "BHEL feels hamstrung by tender conditionalities." The Hindu Business Line, Internet edition ed, April 5, 2005, Chennai. See: http://www.thehindubusinessline.com

Ranganathan, V., 2004. "Electricity Act 2003 -- Moving to a Competitive Environment." *Economic and Political Weekly* 39: 1718.

Rao, S.L., 2002. "The Political Economy of Power." *Economic and Political Weekly* 37.

Rao, S.L., 2003. "Electricity Bill 2001 -- Many shortcoming, but a step forward." *Economic and Political Weekly* 38: 461.

Ray, A., 1999. "One Hundred Years Of Electricity in India." Ganashakti Newsmagazine, Kolkata. See: http://ganashakti.co.in/old/1999/990308/featurenews1.htm

Reddy, A.K.N., 2002. "Towards a New Paradigm for Power Sector Reform in India." *Energy for Sustainable Development* VI: 22.

Reddy, A.K.N., Prasad, K.K., 1980. "Technological Alternatives and the Indian Energy Crisis." In: *Energy Policy for India*. Pachauri, R.K. (ed.). Macmillian Company of India, Delhi.

Reddy, M.S., Venkataraman, C., 2000. "Atmospheric optical and radiative effects of anthropogenic aerosol constituents from India." *Atmospheric Environment* 34: 4511-4523.

Reddy, M.S., Venkataraman, C., 2002. "Inventory of aerosol and sulphur dioxide emissions from India: I - Fossil fuel combustion." *Atmospheric Environment* 36: 677–697.

Reeves, S., Davis, D., Oudinot, A., 2004. "A Technical and Economic Sensitivity Study of Enhanced Coalbed Methane Recovery and Carbon Sequestration in Coal." DOE (March 2004). See: http://www.coal-seq.com/Proceedings2004/TOPICALREPORT_Sensitivity_Study.pdf

Rosenberg, W.G., Alpern, D.C., Walker, M.R., 2005. "The National Gasification Strategy: Gasification of Coal and Biomass as a Domestic Supply Option." Belfer Center for Science and International Affairs, January 2005., Cambridge, MA. (May 2005). See: http://bcsia.ksg.harvard.edu/BCSIA_content/documents/gasification_2005.pdf

Roy, C., 2004. "Technology Development Pursuit - an enabler to sectoral reforms." Energy Technology R&D in India and the United States: Opportunities for Cooperation, 20th August 2004, New Delhi, India.

Roy, S.N., 1999. "Privatisation of Power Distribution in India - Pros & Cons." *Dialogue* 1.

Sachdev, R.K., 1998. "Beneficiation of Coal - an economic option for the Indian power industry." 17th World Energy Congress, September 13-18, 1998, Houston, TX. See: http://www.worldenergy.org/wec-geis/publications/default/tech_papers/17th_congress/2_1_18.asp

Sagar, A.D., 2002. "India's Energy and Energy R&D Landscape: A brief overview." Energy Technology Innovation Project, Kennedy School of Government, Harvard University See: http://bcsia.ksg.harvard.edu/publication.cfm?program=CORE&ctype=paper&item_id=147

Sagar, A.D., Chandra, P., 2004. "Technological Change in the Indian Passenger Car Industry." Energy Technology Innovation Project, Kennedy School of Government, Harvard University, Cambridge, MA. (June 2004).

Sankar, T.L., 2002. "Towards a People's Plan for Power Sector Reform." *Economic and Political Weekly* 39: 4135.

Sankar, T.L., 2004. "Electricity Act 2003: Dark Shadows over a Bright Vision." *Economic and Political Weekly* 39: 839.

Sethi, S.P., 2003. "The Real Barriers/Issues that Restrict Widespread Use of Washed Coal in India." ASCI-STPP Workshop on Clean Coal Technologies for the Indian Power Sector, January 12-16, 2003, Unpublished, Hyderabad, India.

Shah, K.T., 1949. *Power and Fuel: Report of Sub-Commitee*. Vora & Co. Publishers Ltd., Bombay.

Shah, P., Strezov, V., Prince, K., Nelson, P.F., 2008. "Speciation of As, Cr, Se and Hg under coal fired power station conditions." *Fuel*: doi: 10.1016/j.fuel.2007.1012.1001.

Shahi, R.V., 2003. "Power Sector Development: the dominant role of Coal." Conference on Coal and Electricity in India, September 22-23, 2003, IEA, New Delhi, India. See: http://www.iea.org/textbase/work/2003/india/SESS00.PDF

Sharma, D.P., P.S. Chandramohanan Nair, Balasubramanian, R., 2005. "Performance of Indian power sector during a decade under restructuring: a critique." *Energy Policy* 33: 563–576.

Sharma, R., Pervez, Y., Pervez, S., 2005. "Seasonal evaluation and spatial variability of suspended particulate matter in the vicinity of a large coal-fired power station in india—a case study." *Environmental Monitoring and Assessment* 102: 1-13.

Shrestha, R.M., Natarajan, B., Chakaravarti, K.K., Shrestha, R., 1998. "Environmental and power generation implications of efficient electrical appliances for India." *Energy* 23: 1065-1072.

Shukla, P.R., Biswas, D., Nag, T., Yajnik, A., Heller, T., Victor, D.G., 2004. "Impact of Power Sector Reforms on Technology, Efficiency and Emissions: Case Study of Gujarat, India." Center for Environmental Science and Policy, Stanford University, Stanford, CA. See: http://iis-db.stanford.edu/pubs/20453/wp21_gujaratcase_5Mar04.pdf

Siemens, 2005. "Annual Report 2005." Siemens AG See: http://www.siemens.com/Daten/siecom/HQ/CC/Internet/Annual/WORKAREA/gb05_ed/templatedata/English/file/binary/E05_00_GB2005_1336469.pdf

Silveira, S.J., 2001. "The American Environmental Movement: Surviving through Diversity." *Boston College Environmental Affairs Law Review* 28: 497-532.

Simbeck, D., 2004. "CO2 Capture from Power and Fuels." International Petroleum Industry Environmental & Conservation Association (IPIECA) Climate Change Workshop, October 12-13, 2004, Baltimore, MD. See: http://www.ipieca.org/activities/climate_change/downloads/workshops/oct_04/Simbeck_Presentation650.00.ppt

Simbeck, D.R., 2001. "CO2 mitigation economics for existing coal-fired power plants." First National Conference on Carbon Sequestration, May 14-17, 2001, U.S. Dept. of Energy National Energy Technology Laboratory (NETL), Washington DC. See: http://www.netl.doe.gov/publications/proceedings/01/carbon_seq/7c2.pdf

Simmons, M., 2005. *Twilight in the Desert: The Coming Saudi Oil Shock and the World Economy*. John Wiley, Hoboken, NJ.

Singer, C., Holmyard, E.J., Hall, A.R., Williams, T.I., 1958. *A History of Technology*. Oxford University Press, New York.

Singh, A., 2006. "Power sector reform in India: current issues and prospects." *Energy Policy* 34: 2480–2490.

Singh, A.K., Mendhe, V.A., Garg, A., 2006. "CO2 storage potential of geologic formations in India." 8th Greenhouse Gas Technology Conference, Trondheim, Norway.

Singh, V.D., 2006. "Coal Beneficiation (BCCL)." Third US-India Coal Working Group Meeting, April 4-5, 2006, U.S. DOE, Delhi, India. See: http://www.fossil.energy.gov/international/Publications/cwg_april06_cb_bccl.pdf

Singh, V.K., 2005. "Coal Washing and Power Generation from Washery Rejects." Second US-India Coal Working Group Meeting, November 17-23, 2005, U.S. DOE, Washington, DC. See: http://www.fossil.energy.gov/international/Publications/cwg_nov05_singh_washery.pdf

Smouse, S., 2003. "USAID/USDOE NETL Cooperative Activities in India." U.S. DOE

Sobhan, R., 2000. "Governance and Development in South Asia." In: *Problems of Governance in South Asia*. V.A. Pai Panandiker (ed.). Center for Policy Research, Konark Publishers Pvt. Ltd., New Delhi.

Sonde, R.R., 2005. "Indian Perspective on Carbon Sequestration." CSLF Technical Group Meeting, Oveido, Spain. See: http://www.cslforum.org/documents/Oviedo_Indian_Perspective_On_Carbon_Sequestration.pdf

Stephens, J.C., 2005. "Coupling CO2 Capture and Storage with Coal Gasification: Defining "Sequestration-ready" IGCC." Energy Technology Innovation Project, Cambridge, MA. (May 2005).

Subramanian, S.A., 1997. "Monograph on a number of aspects relating to thermal power plant." Central Board of Irrigation and Power, New Delhi.

Sushil, S., Batra, V.S., 2006. "Analysis of fly ash heavy metal content and disposal in three thermal power plants in India." *Fuel* 85: 2676-2679.

TERI, 1986. *TERI Energy Data Directory and Yearbook (TEDDY) 1986*.

TERI, 2001. *Technology status of thermal power plants in India and opportunities in renovation and modernization*.

TERI, 2004. *TERI Energy Data Directory and Yearbook (TEDDY) 2003-04*.

TERI, 2005. *TERI Energy Data Directory and Yearbook (TEDDY) 2004-05*.

Thirumalai, K., 2003. "IGCC." See: http://www.ciigbc.org/documents/Thermal%20.pdf

Tirpak, D., Ashton, J., Dadi, Z., Filho, L.G.M., Metz, B., Perry, M., Schellnhuber, J., Yap, K.S., Watson, R., Wigley, T., 2005. "Report of the International Scientific Steering Committee." Avoiding Dangerous Climate Change: International Symposium on the Stabilisation of greenhouse gas concentrations., 1-3 February 2005, Hadley Centre, U.K. See: http://www.stabilisation2005.com/Steering_Commitee_Report.pdf

Tongia, R., 2003. "The Political Economy of Indian Power Sector Reforms." Stanford University (December 2003).

U.S. DOE, 1999. Clean Coal Today, Fall 1999, Office of Fossil Energy, U.S. Department of Energy.

U.S. OTA, 1978. *The direct use of coal: Prospects and problems of production and combustion*. Office of Technology Assessment, United States Congress, Washington, D.C.

UNDP, 2004a. "Human Development Report." United Nations Development Programme, United Nations, New York.

UNDP, 2004b. "World Energy Assessment, Overview Update 2004." United Nations Development Program (UNDP), New York. See: http://www.undp.org/energy/docs/WEAOU_full.pdf

UNFC, 2004. "United Nations Framework Classification for Energy and Mineral Resources." United Nations See: http://unece.org/ie/se/pdfs/UNFC/UNFCemr.pdf

Varma, J.R., 1997. "Corporate Governance in India: Disciplining the Dominant Shareholder." *IIMB Management Review* 9: 5-18.

Visuvasam, D., Selvaraj, P., Sekar, S., 2005. "Influence of Coal Properties on Particulate Emission Control in Thermal Power Plants in India." Second International Conference on Clean Coal Technologies for Our Future (CCT 2005), Sardinia, Italy.

Wagle, S., Sant, G., Dixit, S., 1998. "Accountability: The Real Crisis in the Power Sector Left Unaddressed." Prayas Energy Group, Pune, India. See: http://www.prayaspune.org/energy/11_Accountability.pdf

Ward, C.R. (Ed.), 1984. *Coal Geology and Coal Technology*. Blackwell Scientific Publications, Boston, MA.

Winfield, M., Horne, M., McClenaghan, T., Peters, R., 2004. "Appendix 4: A Comparison of Combustion Technologies for Electricity Generation from
Power for the Future: Towards A Sustainable Electricity System for Ontario." The Pembina Institute for Appropriate Development (May 2004). See: http://www.pembina.org/pdf/publications/appendix4.pdf

Wolf, M.E., Hidy, G.M., 1997. "Aerosols and Climate: Anthropogenic emissions and trends for 50 years." *Journal of Geophysical Research* 102: 11113-11121.

World Bank, 1993. "The World Bank's Role in the Electric Power Sector." See: http://www.worldbank.org

World Bank, 1997. "A Planner's Guide for Selecting Clean Coal Technologies for Power Plants." World Bank, Washington, D.C.

World Bank, 1999. "Fueling India’s growth & development: World Bank support for India’s energy sector." World Bank, Washington, D.C.

World Bank, 2002. "World Development Indicators." See: http://www.worldbank.org

World Bank, 2005. "World Development Indicators." See: http://www.worldbank.org

World Bank, 2007. "World Development Indicators." Accessed on: July 26, 2007. See: http://www.worldbank.org

Yudovich, Y.E., Ketris, M.P., 2005. "Mercury in coal: a review Part 2. Coal use and environmental problems." *International Journal of Coal Geology* 62: 135– 165.

Appendix A

The tables below provide the results of calculating the arthimetic and geometric means of the technology ratings in the present and the future when the weights for different attributes are doubled. For example, in Table (A), when the ratings for "efficiency" are doubled relative to the ratings for rest of the attributes, the technologies rankings are slightly different relative to the rankings with equal weighting. The technology rankings do not change dramatically with the doubling of weights, with the sole exception of carbon capture—which heavily favors gasification technologies over combustion (see Tables C and D).

A) Present -- Weighted Arithmetic average

Rank	Equal Weight		Ability to use domestic coal		Technology maturity		Low capital cost		Efficiency		Low environmental cost		Indigenous technical capacity			
1	7.2	CFBC (subcritical)	7.6	CFBC (subcritical)	7.6	CFBC (subcritical)	7.4	CFBC (subcritical)	6.6	SC-PC	6.6	CFBC (subcritical)	7.6	CFBC (subcritical)		
2	7.0	Subcritical PC w/o FGD	7.4	Subcritical PC w/o FGD	7.4	Subcritical PC w/o FGD	7.4	Subcritical PC w/o FGD	6.4	USC-PC	6.4	SC-PC	7.4	Subcritical PC w/o FGD		
3	6.8	SC-PC	7.0	SC-PC	7.1	SC-PC	6.9	SC-PC	6.3	CFBC (subcritical)	6.3	IGCC Fluidized	7.0	SC-PC		
4	5.8	USC-PC	5.9	IGCC Fluidized	6.0	USC-PC	5.4	USC-PC	6.1	Subcritical PC w/o FGD	6.1	Subcritical PC w/o FGD	5.6	IGCC Fluidized		
5	5.7	IGCC Fluidized	5.7	USC-PC	5.1	IGCC Fluidized	5.1	IGCC Fluidized	6.0	IGCC Fluidized	6.1	IGCC Moving bed	5.4	USC-PC		
6	5.5	IGCC Moving bed	5.7	IGCC Moving bed	5.0	IGCC Moving bed	5.0	IGCC Moving bed	5.9	IGCC Moving bed	6.0	USC-PC	5.3	IGCC Moving bed		
7	4.8	IGCC Entrained	5.3	PFBC	4.9	IGCC Entrained	4.6	IGCC Entrained	5.4	IGCC Entrained	5.6	IGCC Entrained	4.3	IGCC Entrained		
8	4.5	PFBC	4.3	IGCC Entrained	4.1	PFBC	4.3	PFBC	4.7	PFBC	4.6	PFBC	4.0	PFBC		
9	3.7	Oxyfuel PC/CFBC	4.3	Oxyfuel PC/CFBC	3.3	Oxyfuel PC/CFBC	3.3	Oxyfuel PC/CFBC	3.6	Oxyfuel PC/CFBC	4.0	Oxyfuel PC/CFBC	3.6	Oxyfuel PC/CFBC		

B) Present -- Weighted Geometric mean

Rank	Equal Weight		Ability to use domestic coal		Technology maturity		Low capital cost		Efficiency		Low environmental cost		Indigenous technical capacity			
1	6.6	SC-PC	6.8	SC-PC	6.9	SC-PC	6.6	SC-PC	6.3	SC-PC	6.1	SC-PC	6.8	SC-PC		
2	5.5	CFBC (subcritical)	6.0	CFBC (subcritical)	6.0	CFBC (subcritical)	5.9	CFBC (subcritical)	5.8	USC-PC	5.5	USC-PC	6.0	CFBC (subcritical)		
3	5.3	USC-PC	5.3	USC-PC	5.5	USC-PC	5.2	Subcritical PC w/o FGD	5.1	IGCC Fluidized	5.3	IGCC Fluidized	5.2	Subcritical PC w/o FGD		
4	4.7	IGCC Fluidized	5.2	Subcritical PC w/o FGD	5.2	Subcritical PC w/o FGD	4.9	USC-PC	4.9	IGCC Moving bed	5.1	IGCC Moving bed	4.9	USC-PC		
5	4.6	Subcritical PC w/o FGD	5.0	IGCC Fluidized	4.2	IGCC Fluidized	4.2	IGCC Fluidized	4.3	CFBC (subcritical)	5.0	CFBC (subcritical)	4.8	IGCC Fluidized		
6	4.6	IGCC Moving bed	4.8	IGCC Moving bed	4.1	IGCC Moving bed	4.1	IGCC Moving bed	3.8	IGCC Entrained	3.9	IGCC Entrained	4.5	IGCC Moving bed		
7	3.3	IGCC Entrained	4.1	PFBC	3.5	IGCC Entrained	3.3	IGCC Entrained	3.7	Subcritical PC w/o FGD	3.7	Subcritical PC w/o FGD	2.8	IGCC Entrained		
8	3.5	PFBC	3.2	Oxyfuel PC/CFBC	3.2	PFBC	3.4	PFBC	3.8	PFBC	3.7	PFBC	2.8	Oxyfuel PC/CFBC		
9	2.7	Oxyfuel PC/CFBC	2.8	IGCC Entrained	2.4	Oxyfuel PC/CFBC	2.4	Oxyfuel PC/CFBC	2.8	Oxyfuel PC/CFBC	3.1	Oxyfuel PC/CFBC	2.9	PFBC		

C) Future -- Weighted Arithmetic average

Rank	Equal Weight		Ability to use domestic coal		Technology maturity		Low capital cost		Efficiency		Low environmental impact		Indigenous technical capacity		Carbon capture potential	
1	7.6	CFBC (supercritical)	7.9	CFBC (supercritical)	7.9	CFBC (supercritical)	7.6	CFBC (supercritical)	7.4	CFBC (supercritical)	7.5	IGCC Fluidized	7.8	CFBC (supercritical)	7.4	IGCC Fluidized
2	7.4	SC-PC	7.8	SC-PC	7.8	SC-PC	7.5	SC-PC	7.4	SC-PC	7.4	IGCC Moving bed	7.6	SC-PC	7.3	CFBC (supercritical)
3	7.1	USC-PC	7.1	IGCC Fluidized	7.4	USC-PC	7.0	USC-PC	7.4	USC-PC	7.4	IGCC Entrained	7.1	IGCC Fluidized	7.3	IGCC Moving bed
4	7.1	IGCC Fluidized	7.0	USC-PC	7.1	IGCC Entrained	6.9	IGCC Entrained	7.4	IGCC Fluidized	7.3	CFBC (supercritical)	6.9	USC-PC	7.3	IGCC Entrained
5	7.0	IGCC Moving bed	7.0	IGCC Moving bed	6.8	IGCC Fluidized	6.8	IGCC Fluidized	7.4	IGCC Entrained	7.3	USC-PC	6.9	IGCC Moving bed	7.1	USC-PC
6	7.0	IGCC Entrained	6.8	Subcritical PC w/o FGD	6.8	Subcritical PC w/o FGD	6.8	Subcritical PC w/o FGD	7.3	IGCC Moving bed	7.0	SC-PC	6.8	Subcritical PC w/o FGD	7.0	SC-PC
7	6.3	Subcritical PC w/o FGD	6.4	Oxyfuel PC/CFBC	6.6	IGCC Moving bed	6.6	IGCC Moving bed	5.6	Subcritical PC w/o FGD	5.9	Oxyfuel PC/CFBC	6.8	IGCC Entrained	6.4	Oxyfuel PC/CFBC
8	5.9	Oxyfuel PC/CFBC	6.3	IGCC Entrained	5.5	Oxyfuel PC/CFBC	5.6	Oxyfuel PC/CFBC	5.6	Oxyfuel PC/CFBC	5.6	Subcritical PC w/o FGD	5.6	Oxyfuel PC/CFBC	5.8	Subcritical PC w/o FGD
9	4.1	PFBC	4.9	PFBC	3.8	PFBC	3.8	PFBC	4.6	PFBC	4.5	PFBC	3.8	PFBC	3.8	PFBC

D) Future-- Weighted Geometric mean

Rank	Equal Weight		Ability to use domestic coal		Technology maturity		Low capital cost		Efficiency		Low environmental impact		Indigenous technical capacity		Carbon capture potential	
1	7.3	CFBC (supercritical)	7.6	CFBC (supercritical)	7.6	CFBC (supercritical)	7.4	CFBC (supercritical)	7.2	USC-PC	7.1	USC-PC	7.5	CFBC (supercritical)	7.0	USC-PC
2	7.0	USC-PC	7.3	SC-PC	7.3	SC-PC	7.1	SC-PC	7.1	CFBC (supercritical)	7.1	IGCC Fluidized	7.2	SC-PC	7.0	IGCC Fluidized
3	7.0	SC-PC	6.9	USC-PC	7.2	USC-PC	6.9	USC-PC	7.0	IGCC Fluidized	6.9	IGCC Moving bed	6.8	IGCC Fluidized	6.9	CFBC (supercritical)
4	6.7	IGCC Fluidized	6.8	IGCC Fluidized	6.3	IGCC Fluidized	6.3	IGCC Fluidized	7.0	SC-PC	6.9	CFBC (supercritical)	6.7	USC-PC	6.9	IGCC Moving bed
5	6.6	IGCC Moving bed	6.6	IGCC Moving bed	6.2	IGCC Moving bed	6.2	IGCC Moving bed	6.9	IGCC Moving bed	6.5	SC-PC	6.5	IGCC Moving bed	6.5	SC-PC
6	5.8	IGCC Entrained	5.7	Oxyfuel PC/CFBC	6.0	IGCC Entrained	5.8	IGCC Entrained	6.2	IGCC Entrained	6.2	IGCC Entrained	5.7	IGCC Entrained	6.1	IGCC Entrained
7	5.3	Oxyfuel PC/CFBC	4.6	Subcritical PC w/o FGD	4.9	Oxyfuel PC/CFBC	5.1	Oxyfuel PC/CFBC	5.1	Oxyfuel PC/CFBC	5.4	Oxyfuel PC/CFBC	5.1	Oxyfuel PC/CFBC	5.7	Oxyfuel PC/CFBC
8	4.1	Subcritical PC w/o FGD	4.6	IGCC Entrained	4.6	Subcritical PC w/o FGD	4.6	Subcritical PC w/o FGD	3.4	Subcritical PC w/o FGD	3.4	Subcritical PC w/o FGD	4.6	Subcritical PC w/o FGD	3.8	Subcritical PC w/o FGD
9	2.5	PFBC	2.9	PFBC	2.2	PFBC	2.2	PFBC	2.9	PFBC	2.8	PFBC	2.2	PFBC	2.2	PFBC

BELFER CENTER FOR SCIENCE AND INTERNATIONAL AFFAIRS
JOHN F. KENNEDY SCHOOL OF GOVERNMENT
HARVARD UNIVERSITY

Discussion Paper Series
Last updated: Tuesday, 3/21/2008

2008-03	Suarez, Marcial A. “Essay on Twenty-first-century Terrorism: Definitional Problem of Complex Political Environments.”
2008-01	Gallagher, Kelly Sims. “Synthesis of Comments Received on ‘Policy Options for Reducing Oil Consumption and Greenhouse-Gas Emissions from the U.S. Transportation Sector.’”
2007-06	Chikkatur, Ananth, and Ambuj Sagar. “Cleaner Power in India: Towards a Clean-Coal-Technology Roadmap.”
2007-05	Gallagher, Kelly Sims, Gustavo Collantes, John P. Holdren, Henry Lee, and Robert Frosch. “Policy Options for Reducing Oil Consumption and Greenhouse-Gas Emissions from the U.S. Transportation Sector.”
2007-04	Kovchegin, Dmitry. “A Russian Perspective on Cooperation Threat Reduction.”
2007-03	Kokoshin, Andrei A. “Nuclear Conflict in the Tweny-first Century.”
2007-02	Decker, Debra K., and Erwann O. Michel-Kerjan. “A New Energy Paradigm: Ensuring Nuclear Fuel Supply and Nonproliferation through International Cooperation with Insurance and Financial Markets.”
2007-01	Potter, Philip. “Leadership Experience and American Foreign Policy Crises.”
2006-06	Chenoweth, Erica. “The Inadvertent Effects of Democracy on Terrorist Group Emergence.”
2006-05	Olmstead, Sheila M., W. Michael Hanemann, and Robert N. Stavins. "Do Consumers React to the Shape of Supply? Water Demand Under Heterogeneous Price Structures.”
2006-04	Bullock, Graham. "Engaging Voices: Stakeholders and the Development of National Environmental Indicators; Case Studies from the Sustainable Roundtables, EPA, and the Heinz Center."
2006-03	Toft, Monica Duffy. “Religion, Civil War, and International Order.”
2006-02	Flynn, Jules. "Taxes and Charges to Manage Oil Demand in Australia: Policy Recommendations for the Australian Federal Government."
2006-01	Bilmes, Linda. “The Economic Costs of the Iraq War: An Appraisal Three Years After the Beginning of the Conflict.”
2005-10	Saradzhyan, Simon and Nabi Abdullaev. “Disrupting Escalation of Terror in Russia to Prevent Catastrophic Attacks.”
2005-09	Stephens, Jennie C. “Coupling CO2 Capture and Storage with Coal Gasification: Defining “Sequestration-Ready” IGCC.”
2005-08	Stephens, Jennie C., and Bob van der Zwaan. “CO2 Capture and Storage (CCS): Exploring the Research, Development, Demonstration, and Deployment Continuum.”

The Belfer Center for Science and International Affairs (BCSIA) Discussion Papers, established in 1991, will be issued on an irregular basis with three programmatic subseries: International Security; Science, Technology, and Public Policy; and Environment and Natural Resources. Inquiries and orders may be directed to: Belfer Center for Science and International Affairs, Publications, Harvard University, 79 JFK Street, Cambridge, MA, 02138.

BELFER CENTER FOR SCIENCE AND INTERNATIONAL AFFAIRS
JOHN F. KENNEDY SCHOOL OF GOVERNMENT
HARVARD UNIVERSITY

Discussion Paper Series
Last updated: Tuesday, 3/21/2008

2005-07	Lee, Henry. "Dawning of a New Era: The LNG Story." April 2005.
2005-06	Stavins, Robert S. “The Effects of Vintage-Differentiated Environmental Regulation.”
2005-05	Lubowski, Ruben, Andrew Plantinga, and Robert Stavins. “Land-Use Change and Carbon Sinks: Econometric Estimation of the Carbon Sequestration Supply Function.”
2005-04	Stavins, Robert S. “Environmental Economics.”
2005-03	Belloni, Roberto. "Is Humanitarianism Part of the Problem? Nine Theses."
2005-02	Ghosh, Debyani. "Assessment of Advanced Coal-Based Electricity Generation Technology Options for India."
2005-01	Rosenberg, William G., Dwight C. Alpern, and Michael R. Walker. "The National Gasification Strategy: Gasification of Coal & Biomass as a Domestic Supply Option."
2004-09	Srinivas, Smita, “Demand Policy Instruments for R&D: Procurement, Technical Standards and the Case of Indian Vaccines[12].”
2004-08	Rosenberg, William G., Dwight C. Alpern, and Michael R. Walker, "Deploying IGCC in This Decade With 3 Party Covenant Financing." Vol. II
2004-07	Rosenberg, William G., Dwight C. Alpern, and Michael R. Walker, "Deploying IGCC in This Decade With 3 Party Covenant Financing." Vol. I
2004-06	Rapporteur's Report, “Workshop on Integrated Gasification Combined Cycle: Financing and Deploying IGCC Technology in this Decade.”
2004-05	Sagar, Ambuj and Pankaj Chandra. “Technological Change in the Indian Passenger Car Industry.”
2004-04	Vladimir Dvorkin. “The Russian Debate on the Nonproliferation of Weapons of Mass Destruction and Delivery Vehicles.”
2004-03	Loizides, Neophytos G., and Marcos A. Antoniades. "Settlers, Refugees, and Immigrants: Alternative Futures for Post-Settlement Cyprus."
2004-02	Pressman, Jeremy. “If Not Balancing, What? Forms of Resistance to American Hegemony.”
2004-01	Rosenberg, William G., Dwight C Alpern, and Michael R. Walker. “Financing IGCC - 3Party Covenant.”
2003-13	Garcia, Denise. "The Diffusion of Norms in International Security: The Cases of Small Arms and Landmines."
2003-12	Garcia, Denise. "Analyzing the Issue of Curbing the Unrestricted Availability and Proliferation of Small Arms and Light Weapons."

The Belfer Center for Science and International Affairs (BCSIA) Discussion Papers, established in 1991, will be issued on an irregular basis with three programmatic subseries: International Security; Science, Technology, and Public Policy; and Environment and Natural Resources. Inquiries and orders may be directed to: Belfer Center for Science and International Affairs, Publications, Harvard University, 79 JFK Street, Cambridge, MA, 02138.