CLEAN COAL POWER GENERATION TECHNOLOGY REVIEW: WORLDWIDE EXPERIENCE AND IMPLICATIONS FOR INDIA

Background Paper

India: Strategies for Low Carbon Growth

June 2008
The World Bank

CONTENTS

Acknowledgements

This report was produced by Stratos Tavoulareas (consultant, World Bank) as a background paper for the study, *India: Strategies for Low Carbon Growth*. The following World Bank consultant has worked on this paper: Valuable comments were received from Ranjit Lamech, Masami Kojima, Gary Stuggins, Masaki Takashashi and Michael Stanley. Kseniya Lvovsky is the former Task Team Leader for the study, Kwawu M. Gaba is the current Task Team Leader, Charles J. Cormier is the current co-Task Team Leader, Karin Kemper and Salman Zaheer are responsible Sector Managers, and Isabel M. Guerrero is the Country Director, India.

Acronyms and Abbreviations

CCS	Carbon Capture and Sequestration
CCT	Clean Coal Technologies
CEA	Central Electricity Authority
CFB	Circulating Fluidized Bed Combustion
CO2	Carbon dioxide
EPDC	Electric Power Development Corp. of Japan
EPRI	Electric Power Research Institute
FGD	Flue Gas Desulfurization
GTI	Gas Technology Institute
GW	Gigawatt (electric)
HHV	Higher Heating Value
IGCC	Integrated Gasification Combined Cycle
MW	Megawatt (electric)
MWth	Megawatt (thermal)
NTPC	National Thermal Power Corp. of India
O&M	Operation and Maintenance
OECD	Organization for Economic Cooperation and Development
R&M	Renovation and Modernization
US AID	US Agency for International Development
US DOE	US Department of Energy
UCG	Underground Coal Gasification
UK	United Kingdom
USC	Ultra-SuperCritical pulverized coal technology

Executive Summary

The purpose of this report is to provide an overview of the clean coal technologies (CCT) used in power generation worldwide and draw preliminary recommendations regarding the utilization of CCT options which are suitable for application in India. The report was commissioned by the World Bank at the request of the Government of India and is also intended to provide input regarding the CCTs to be evaluated further under the World Bank study on *Low-Carbon Growth for India*.

As of the end of 2005, the installed coal-fired capacity worldwide was 1,289 GWs and coal generated approximately 64 percent of the total electricity produced. The majority of these plants (74 percent) utilize subcritical pulverized coal technology, but a substantial percentage, 22 percent of the installed coal-fired capacity, is supercritical and ultra-supercritical (USC). Supercritical and USC are fully commercial options, are suitable for all coals and can achieve significant efficiency improvements over the subcritical design leading to 10-20 percent CO2 reduction. In the past, supercritical and USC were used mostly in OECD countries, but in the last 10-15 years developing countries are using them too; for example, China had 30 GWs installed capacity (utilizing supercritical technology) at the end of 2006 and is expected to have 120 GWs by the end of 2007.

Circulating Fluidized Bed Combustion (CFB) has gained significant acceptance (40,000 MWs or 3.10% of the total installed coal-fired capacity), but it is mainly used with low quality fuels and plant efficiency similar to subcritical plants. CFB can be designed for supercritical conditions, but only one such plant is being planned presently.

Integrated Gasification Combined Cycle (IGCC) for hard coal is a commercial option with approximately 3,500 MWs in operation, but not economically competitive yet. It promises to achieve higher efficiency and may have a competitive advantage as its costs are reduced with more experience being accumulated and if carbon capture and sequestration (CCS) are required in the future.

Cost-effectiveness depends on site-specific requirements, but in most cases (especially with present fuel prices) supercritical or USC technology is the least cost option.

Assessment of the CCTs for India should keep in mind the key drivers:

- Maximizing efficiency of the coal resource, both domestic and imported, is of strategic importance for India. This is driven by energy security considerations, as well as economics (as coal is the least cost option) and the need to reduce environmental impacts.
- Also, India needs reliable and affordable electricity. Hence, the highest efficiency technology may not be necessarily the best choice, if it is not reliable; a trade-off between reliability (and other technology risks) and efficiency may be needed.
- For many years, India is suffering from lack of adequate supply to meet electricity demand. Closing this gap is of paramount importance for the country.

- While the power industry in India has good experience in burning the domestic coal, a very high ash fuel, some of the new technologies may need a gestation period before they achieved adequate reliability.
- There are other physical constraints such as lack of land and water, and inability of the power plant suppliers to meet tight delivery schedules.

With these drivers and constraints in mind, the utilization of CCTs globally and in India was reviewed, and the following preliminary recommendations are made:

- ***Supercritical technology should be pursued in India***, a strategy consistent with the guidelines developed by the Central Electricity Authority of India on new thermal power plants[1]. India's goal to have 60 percent of the new coal-fired plants built during the 12th 5-Year Plant (2012-2016) using supercritical technology is appropriate, but higher steam conditions should be sought. As recommended by CEA, new units should be of 600-1,000 MW size and utilize supercritical steam conditions in the 568°C-593°C range. After 10-15 units are implemented with these conditions, the next group of units should utilize higher steam temperatures. This should continue until India uses the state-of-the-art technology (presently referred to as USC with steam temperatures 605°C in China and 625°C in Japan). The ultra-mega projects being implemented in India provide an excellent framework (with regard to institutional capacity to finance, plan, construct and operate such plants). Introduction of supercritical technology in India should be accompanied by an institutional capacity-building program which includes training on plant operation and maintenance, water chemistry control, etc., and is directed especially at the State Electricity Boards (SEB).

- While supercritical and ultra-supercritical plants are introduced, it is realistic to expect that ***subcritical plants will continue being manufactured and used***. Shorter lead times for these plants, capacity to produce them by local manufacturers and familiarity by the electric utilities of India are factors making them attractive, at least for the short-term (next 10 years). ***However, these plants should be as large as possible (e.g., 500 MW) and be designed with high efficiency in mind, preferably with steam conditions: 16.9 MPa/538°C/565°C***.

- India has nearly 50 GWs of installed capacity represented by units 11-30 years old which have reduced reliability, output and efficiency relative to design conditions. Some of these plants should retire, others be rehabilitated and other be replaced with new state-of-the-art units. The Government has identified the units which belong in each of these three categories and is implementing its strategy. However, ***more resources should be mobilized and directed at improving plant efficiency through rehabilitation.*** Rehabilitation of existing units is facing some obstacles including lack of adequate financing, lack of interest for such projects by the large power plant suppliers (who are overbooked

[1] CEA, "*Report of the Committee to recommend next higher size of coal-fired thermal power stations*", November, 2003

with orders for new power plants) and difficulty in guaranteeing performance of the rehabilitated plants. Further support is needed to remove or mitigate these barriers. The World Bank, with support from GEF (Global Environment Facility) Program, is working in this direction.

- CFB technology is already used in India burning lignite and other low quality fuels. If SO2 emission regulations are introduced in the future, it is likely that this technology will be used more. ***CFB, as well as pulverized coal plants, could burn biomass too*** (***biomass co-firing)***, an option considered "CO2-neutral".

- IGCC technology utilizing imported coal is ready for commercial application, but non-competitive compared to pulverized coal plants. ***The decision to implement IGCC with imported coal relates to the country's strategy to participate in the advancement of this technology and be better prepared in case CCS is required in the future***. ***Fluidized bed IGCC technology***, which is the only gasification option suitable for Indian coal, i***s still in early stage of development and requires demonstration*** at approximately 100 MW size. Pursuing this technology is also a strategic, not an economic, decision. Certain Indian organizations have become interested in Underground Coal Gasification, but, there is no adequate information to determine whether this option is feasible, not to mention cost-effective.

- ***An integrated coal chain analysis should be carried out including assessment of the coal resource, potential for beneficiation (coal cleaning), transport costs and linkage to clean coal conversion technologies***. Coal washing is being promoted already, but a more thorough evaluation is needed in the context of the complete coal chain considering reduction of the carbon intensity, too. The result will be a clean coal strategy for coal mining and coal-based power generation, and specific policies may emerge, some of which could be new and others refinements of existing regulations on coal washing (cleaning) and CCT initiatives.

- ***Carbon capture and sequestration is being considered worldwide as a key option for climate change response.*** While CCS is not required yet, ***India should consider assessing its sequestration potential (geology) and monitor CCS-related developments***. CCS may have a significant impact on the competitiveness of the various technologies. The key coal-fired options are:
  - High efficiency (USC) pulverized coal plants with CCS;
  - IGCC with CCS; and
  - Oxy-fuel with CCS.

  Presently, there is no clear winner among these three options, as there are many outstanding issues, and the industry is pursuing all of them. ***Whether India decides to be involved in such technological developments or not relates to its overall climate change strategy.***

1. Introduction

The purpose of this report is to provide an overview of the utilization of clean coal power generation technologies (CCT) worldwide with special attention to those suitable for India. The report, commissioned by the World Bank at the request of the Government of India, is intended to assist in identifying the most appropriate scenarios (involving utilization of one or more clean coal technologies) to be evaluated further under the World Bank study of the *Low-Carbon Growth* Strategy for India. This version of the report reflects comments received during consultations with key stakeholders during the World Bank Mission in India, which took place in September 17 – 28, 2007.

The term *Clean Coal Technologies (CCT)* is used to mean *every option capable of reducing emissions upstream, downstream, or within the power generation (energy conversion) process.* However, for the purpose of this report, a subset of CCTs is being reviewed which have the potential to reduce greenhouse gas emissions in power generation. For new power plants, the following options are considered:

- Supercritical and ultra-supercritical (USC) pulverized coal technologies;
- Circulating fluidized bed combustion (CFB); and
- Integrated gasification combined cycle (IGCC).

For existing power plants, the potential for efficiency improvement is explored as part of rehabilitation (Renovation and Modernization (R&M) as it is commonly called in India). Also, co-firing of biomass in pulverized coal and CFB boilers is discussed briefly; this is an option for both existing and new power plants. Description of these technologies is not included in this report, as there are numerous publications which provide comprehensive description[2].

The report is organized into three sections. After the introduction (Section 1), the experience with clean coal technologies worldwide is summarized in Section 2. It has been a challenge (in this section) to gather the most up-to-date information, mainly because most countries do not provide adequate details on the technologies being used (e.g., steam conditions). Also, in most countries the latest reports reflect data from 2005. However, developments in the last couple of years are significant especially in China, where a few new power plants are being built every week. For this reason, the approach followed in this report was to utilize official published data mostly reflecting 2005 conditions, but supplement them with recent reports from various sources.

Section 3 provides information on the utilization of CCT in India and preliminary recommendations regarding India's strategy regarding CCT utilization. Accelerated

[2] *World Bank, "Technical and Economic Assessment of Grid, Mini-Grid and Off-Grade Electrification Technologies", September, 2006, available at:*
http://siteresources.worldbank.org/EXTENERGY/Resources/336805-1157034157861/ElectrificationAssessmentRptSummaryFINAL17May07.pdf

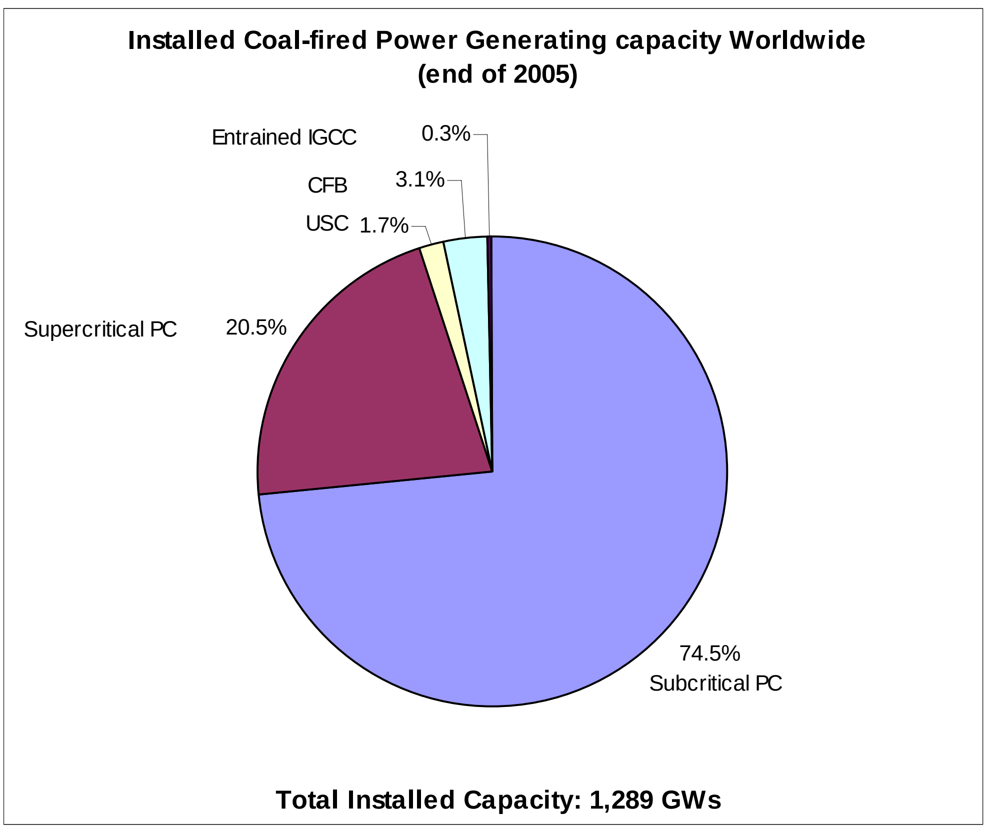
deployment of some of these options may result in significant CO_2 emission reduction and should be evaluated further in India's *low carbon growth strategy study*.

Information on carbon capture and sequestration (CCS) is presented in Appendix 1. CCS is not required presently in any country, but it is an option that can significantly reduce net carbon dioxide emissions from coal-fired power plants. As such, CCS is receiving serious consideration as part of a future greenhouse gas reduction framework and could significantly affect the competitiveness of coal-firing technologies. Finally, Appendix 2 includes charts on the relationship between power plant steam conditions and efficiency for reference purposes.

2. Experience with Clean Coal Technologies Worldwide

Presently, coal-based power plants contribute approximately 64 percent of the total electricity generated worldwide. As of the end of 2005, the installed coal-fired power generating capacity worldwide was 1,289 GW[3]. Figure 1 shows the utilization of various coal-firing technologies.

Figure 1: Installed Coal-fired Power Generation Capacity Worldwide



[3] Paelinck, Philippe, "Addressing clean power and CO2", Alstom, Presentation at World Bank, Aug 29, 2007

Table 1 provides more statistics on the utilization of various power generation technologies worldwide and in selected countries. The installed capacities in Table 1 refer to existing power plants.

The majority of coal-fired power plants (74 percent) worldwide utilize subcritical pulverized coal technology. However, a substantial percentage, 22 percent of the installed coal-fired capacity, is supercritical and USC, which is a fully commercial option suitable to all coals and with a significant efficiency improvement over the subcritical plants. Most supercritical and USC plants are using hard coal, but there numerous using low rank coals with high ash in countries such as Germany, Greece and Poland. India has ordered six 660 MW supercritical units, which are under construction.

Commercial adoption of ultra-supercritical technology (USC) is limited to a few countries (Denmark, Germany and Japan), but is expanding rapidly, most impressively in China which is already building numerous USC plants and has acquired the technology for local manufacturing. Supercritical and USC used to represent a small percentage of the newly ordered power plants (10-30 percent) before 2002, but in recent years they are more than 60 percent.

Table 1: Statistics on Coal-fired Power Generation Technologies Worldwide (end of 2005)[4]

	Installed Coal-fired	SubCr PC	SC PC	USC	Adv USC	CFB	IGCC Entrained	IGCC FB
Worldwide (MWs)	1,289,000	960,229	263,740	21,583	0	40,000	3,448	0
Worldwide (%)	100.00	74.5	20.5	1.7	0.0	3.1	0.3	0.0
USA	335,892	251,324	75,000	0	0	8,800	768	
Japan	43,214	12,019	13,800	17,115	0		280	
Germany (estimated)	52,600	38,844	8,488	3,468	0	1,800		
Russia (estimated)	44,600	32,840	11,760		0			
China (end of 2006)	400,000	360,000	28,000	2,000	0	10,000		
India	67,710	66,499	0	0	0	1,211		
Status		Comm	Comm	Comm	Under Dev	Comm	Comm	Under Dev
Suitability for India		Yes	Yes	Yes; after SC	Yes	Yes	Imported Coal	Yes

SubCr: Subcritical; SC: Supercritical; FB: Fluidized Bed; Under Dev: Early stages of development (pre-demonstration)
Sources: Alstom Corp., JCoal of Japan, JPower of Japan, US Energy Information Administration, World Bank, etc.

CFB technology is being used worldwide, in both Organization for Economic Cooperation and Development (OECD) and developing countries. It is commercially available in sizes up to 300 MW (single boiler). While 500 and 800 MW CFBs are being developed, multiple CFB boilers are utilized to achieve higher output. For example, a 1,000 MW CFB plant is feasible today consisting of 4X250 MW CFB boilers with 2X500 MW steam turbines. A key advantage of CFB is that it is suitable for low rank coals. Also, manufacturing of CFB boilers can be done in the same facilities which manufacture conventional boilers; so localization of the technology in developing countries is easier. While CFB is used mostly on low quality fuels without serious consideration to plant efficiency, CFB can be designed with supercritical and USC steam conditions and can achieve efficiencies. In general, CFB is considered to have plant efficiency similar to pulverized coal plants with the same steam conditions and FGD.

[4] The data in this table are preliminary; they will be finalized in the final draft of the report

The entrained version of IGCC has been used in numerous large (up to 550 MW) power plants. However, the technology is not competitive yet compared to supercritical and USC which can achieve similar efficiencies at a lower cost. The advantage of IGCC technology is that it has the potential to achieve higher efficiencies in the future (assuming that certain technological developments take place); also, it may be more cost-effective (both in terms of CO_2 cost-effectiveness and cost of power generation) than supercritical and USC if carbon capture and sequestration (CCS) is required.

For Indian coals, fluidized bed gasification is the most suitable option. However, this technology is still in the early stages of development. The largest size plants are a few 150 tpd (tons of coal per day) U-Gas gasifiers in China in non-power generation applications. Also, these plants are air-blown. Considering that oxygen-blown IGCC would be preferable in case CCS is needed, future technology developments would need to focus on oxygen-blown fluidized bed gasification. The next step is a demonstration at approximately 100 MW scale.

Recently, the concept of underground coal gasification (UCG) is receiving renewed interest with two technologies being considered: the *Vertical wells method* developed by the Former USSR and the *coal seams method* developed in China, Europe and North America. China, Russia and Uzbekistan have UCG facilities in operation, but the technology is still in the early development stage and there is not adequate information available to comment on its feasibility and suitability for India.

Table 2 provides typical efficiencies and costs for the power generation options included in this report. The costs reflect new state-of-the-art power plants of typical sizes (for example, pulverized coal plants above 500 MWs, CFB of 200-300 MW and IGCC of 400-700 MW) in OECD countries. As described in the report, costs in China are significantly lower and in India in between Chinese and OECD costs.

Table 2: Typical Efficiencies and Costs

	SubCr PC	SC PC	USC	Adv USC	CFB	Entrained	IGCC FB	IGCC MB
Efficiency (%HHVnet)	35.0-38.0	38.0-40.0	40.0-42.5	42.5-46.0	35.0-38.0	38.0-41.0	38.0-41.0	38.0-41.0
Capital ($/kW)	1300-1500	1350-1550	1400-1650	NA	1200-1500	1700-2000	NA	NA
Fixed O&M ($/kW-yr)	40.5	40.8	41.1	NA	42.2	52	NA	NA
Variable O&M ($/MWh)	1.7	1.65	1.6	NA	3.4	3.2	NA	NA

MB: Moving Bed; Sources: World Bank

The remaining of this section provides more details on each of the technologies being considered.

Pulverized Coal Technology

Pulverized coal technology is the most widely used coal-firing option worldwide. The steam conditions (pressure and temperature) at the inlet of the steam turbine define different types of pulverized coal plants and determine (along with the coal characteristics and ambient conditions) the plant efficiency:

- *Subcritical pulverized coal* plant has steam outlet pressure below 22.1 MPa. Typical steam outlet temperatures (superheat and reheat, respectively) are: 538^{o}C/538^{o}C and net plant efficiency (HHV-basis) of 35-38 percent[5] for most coals and countries. As an example, a reference plant in the US (subcritical burning Bituminous coal in standard US ambient and design conditions)[6] is estimated to have plant efficiency of to be 37.7 percent (HHVnet).
- *Supercritical pulverized coal plants* have steam outlet pressure above 22.1 MPa. Typically, the pressure is 24.7 MPa and the steam outlet temperatures 538-565^{o}C/565^{o}C resulting in net plant efficiency of 38-40 percent. The same US DOE study estimates that reference supercritical plant in the US would have an efficiency of 39.1 percent (HHVnet), or 1.4 percentage points higher that the subcritical.
- *Ultra-supercritical pulverized coal (USC) plants* have steam outlet pressure above 22.1 MPa, typically around 27 MPa, and the steam outlet temperatures in the 565^{o}C to 625^{o}C range. Net plant efficiency in the 40.0-42.5 percent range.
- *Advanced USC* plants have steam outlet pressure above 22.1 MPa and steam outlet temperatures above 625-650^{o}C. Typical net plant efficiency: 42.5-46.0 percent.

The above plant efficiencies apply to most countries. In northern European countries (e.g., Denmark), efficiencies above the upper end of the range have been reported mainly due to ambient conditions (temperature and pressure), good quality coal and low stack temperature (made possible by the low-sulfur content of the coal). Countries with warm climate and low quality coals such as India experience lower efficiencies, but there are still estimated to be within the range shown in Table 1, even though closer to the lower end of the range.

All the above types of pulverized coal plants are commercially available in sizes up to 1,000 MW, except for the "advanced USC" which is still under development. Multiple suppliers exist (see below) to have adequate competition.

As Table 1 and Figure 1 show, the majority of the coal-fired plants in the world are subcritical. However, more than 520 units representing an estimated 300 GW (22 percent of the total coal capacity) utilize supercritical and USC steam conditions[7] and operate in the following countries:

- 155 units (ranging in size from 300 to 1,100MW each) operate in the United States representing approximately 107 GW; 109 of these units representing 75 GWs burn coal; the remaining are burning natural gas and oil.

[5] These efficiencies reflect actual efficiencies; efficiencies such as the DOE study are estimates, but they have also taken into account actual plant data. Only designs which do not have operating experience such as the "advanced USC" are estimated numbers and can not be confirmed with actual experience
[6] US DOE, "Cost and performance baseline for fossil energy plants", DOE/NETC-2007/1281, May 2007
[7] Power Magazine, "A critical look at supercritical power plants", April 2004 pgs 42-49

- More than 53 units operate in Western Europe, ranging in size from 200 to 1,000 MW each. Most of these units are supercritical, but six are USC representing 4,268 MW. The supercritical and USC plants are in the following countries:

Country	No. of Units	Installed Capacity (MW)
Austria	1	405
Denmark	6	2,379
Finland	1	550
Germany	22	11,956
Greece	1	330
Holland	4	2,510
Italy[8]	18	11,760
UK	2	750

Characteristics for selected plants in Europe are shown in Table 3.

Table 3: Sample of European Supercritical Plants

Power Plant	Fuel	Output MW	Steam Conditions MPa/°C/°C/°C	Startup Date
Denmark				
Skaerbaek	Coal	400	29/582/580/580	1997
Nordiyland	Coal	400	29/582/580/580	1998
Avdoere	Oil, Biomass	530	30/580/600	2000
Germany				
Schopau A,B	Lignite	450	28.5/545/560	1995–96
Schwarze Pumpe A,B	Lignite	800	26.8/545/560	1997–98
Boxberg Q,R	Lignite	818	26.8/545/583	1999–2000
Lippendorf R,S	Lignite	900	26.8/554/583	1999–2000
Bexbach II	Coal	750	25/575/595	1999
Niederausem K	Lignite	1000	26.5/576/599	2002

Source: World Bank/EPRI

- There are approximately 108 supercritical units in Japan representing 68 GW of installed capacity. However, these include coal-, oil- and gas-fired units. About 50 units are coal-fired ranging in size from 500 to 1,000 MW; 21 of these units are USC representing an installed capacity of 17.1 GW. Table 4 shows the most recent USC plants in Japan.
- The Republic of Korea has 20 units representing about 13,000 MW. It utilizes standardized design of 500 MW (25 MPa/538^{o}C/565^{o}C) and 800 MW (25 MPa/565^{o}C/565^{o}C).

[8] Some of these plants may be oil-fired or gas-fired

- Former USSR had approximately 250 supercritical units[9] of standardized design: 300 MW, 500 MW, 800 MW and 1,200 MW. In Russia, most of the supercritical plants have 538°C or 565°C steam temperatures (e.g., Permskaya, Sredneuralskaya, Nizhnevartovskaya, Kostromskaya, and Surgutskaya power plants). However, there are plants with higher steam conditions such the Sochicskaya TES and Severozapandaya GRES-2 plants, which have plant efficiency above 40 percent (HHV).

- As of the end of 2006, China had 46 supercritical plants in operation representing 30 GWs of installed capacity; most of them have been designed for 24.7 MPa/565°C/565-593°C, but two have steam conditions: 24.7 MPa/600oC/600oC. By the end of 2007, approximately 120 GWs of installed capacity will be utilizing supercritical conditions.[10]

Table 4: Coal-fired Ultra-supercritical Plants in Japan

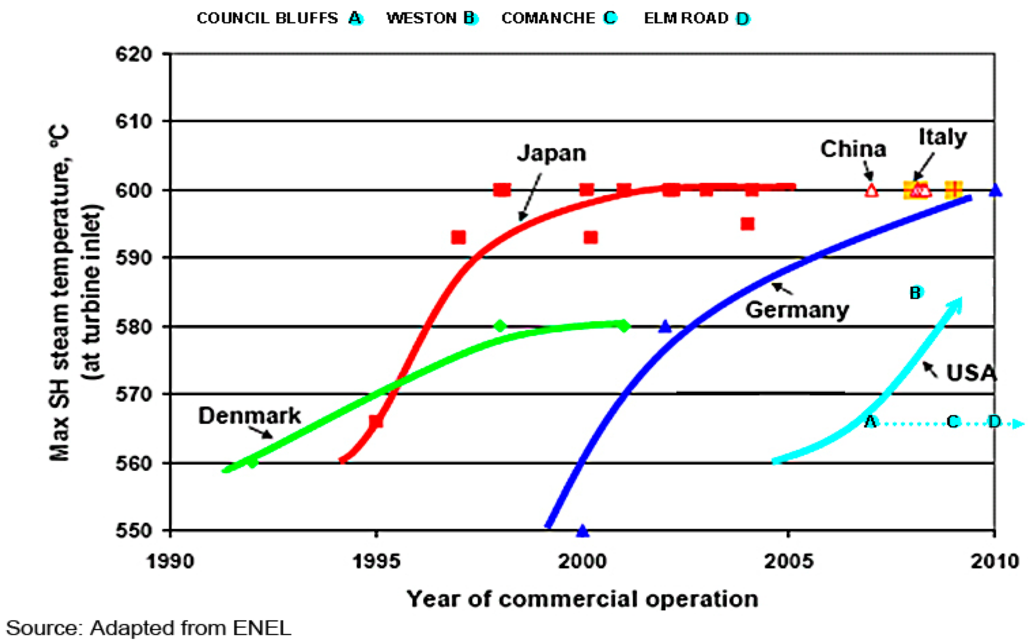
Unit	**Company**	Output MW	Steam Conditions MPa/°C/°C	Startup
Hekinan #4	Chubu	1000	24.6/566/593	2001
Hekinan #5	Chubu	1000	24.6/566/593	2002
Tsuruga #2	Hokuriku	700	24.6/593/593	2000
Tachibana-wan	Shikoku	700	24.6/566/566	2000
Karita #1 (PFBC)	Kyushu	350	24.6/566/593	2000
Reihoku #2	Kyushu	700	24.6/593/593	2003
Tachibana-wan #1	EPDC	1050	25/600/610	2000
Tachibana-wan #2	EPDC	1050	25/600/610	2001
Isogo #1	EPDC	600	25.5/600/610	2002
Hitachinaka #1	Tokyo	1000	24.5/600/600	2002
Maizuru #1	Kansai	900	24.1/593/593	2003
Maizuru #2	Kansai	900	24.1/593/593	2003
Isogo #1	EPDC	600	25.5/600/625	Under construction

Source: World Bank/EPRI

Figure 2 shows the progress made by different countries in advancing plant steam conditions and corresponding efficiency over the last 20 years.

[9] Some of these plants may be oil-fired or gas-fired
[10] Prof. Mao, Jianxiong, “Electrical Power Sector and Supercritical Units in China” presented at the Workshop on Design of Efficient Coal Power Plants, Vietnam, October 15-16, 2007

Figure 2: Historical Development of Plant Design Conditions



Most of the *supercritical plants* worldwide burn hard coal, but there are numerous burning low grade coals, too. A sample of supercritical plants burning low grade coal includes:

- Belchatow, Poland (833 MW).
- Florina, Greece; a 330 MW plant burning very low quality lignite (steam conditions: 23.5MPa/540^{o}C/540^{o}C).
- Patnow, Poland (460 MW).

The coal burned in these plants has low heating value mainly due to high moisture, but it has relatively low ash. High-ash coal plants operate in Russia, including eight 500 MW units burning Ekibastuz basin coal in Russia with ash ranging from 36 to 72 percent (averaging 44 percent)[11]. In addition to Ekibastuz basin, the Karaganda and Kiselovsk basins have coals similar to Indian coals, bituminous with high ash (averaging 30-40 percent), which have been utilized in supercritical units.

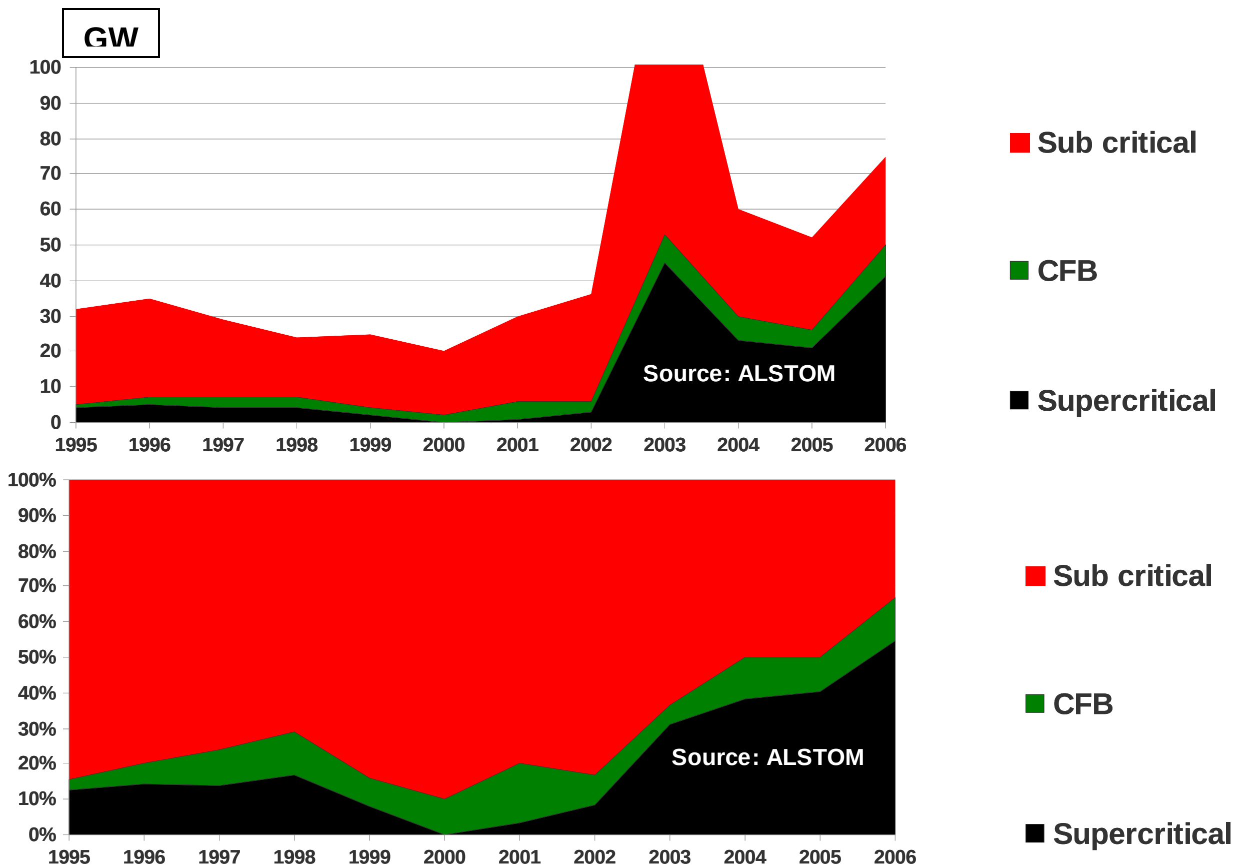
USC plants burning low grade coals include:

- Niederaussem, Germany; 1000 MW unit with 580^{o}C/600^{o}C steam conditions;
- Neurath F/G, Germany; 2X1100 MW units with 600^{o}C/605^{o}C steam conditions; and
- Boxberg R, Germany; 670 MW with 600^{o}C/610^{o}C steam conditions (under construction).

[11] Armor, A.F and Oliker, I, "*Boiler design for low rank coal in the Former USSR*", *EPRI, 2002*

While many countries are utilizing state of the art technologies, subcritical power plants continue to be built. In some cases, economics favor the subcritical option; site-specific factors which contribute to this include low fuel costs (e.g., in mine-mouth plants), hesitancy to change the plant design to control spare part costs (especially if a standardized design is used) and avoid additional training of engineers and plant operators. In other cases, there is clear preference for local manufacturing which can produce only subcritical plants. Figure 3 shows the orders of steam plants by type (subcritical, supercritical and CFB) worldwide except China as recorded by Alstom Corp. It shows a clear preference for supercritical in recent years; subcritical represented 70-90 percent of the orders before 2002, but it has been reduced to only 40 percent by 2006.

Figure 3: Historical Data for Sales of Steam Plants (by boiler type)

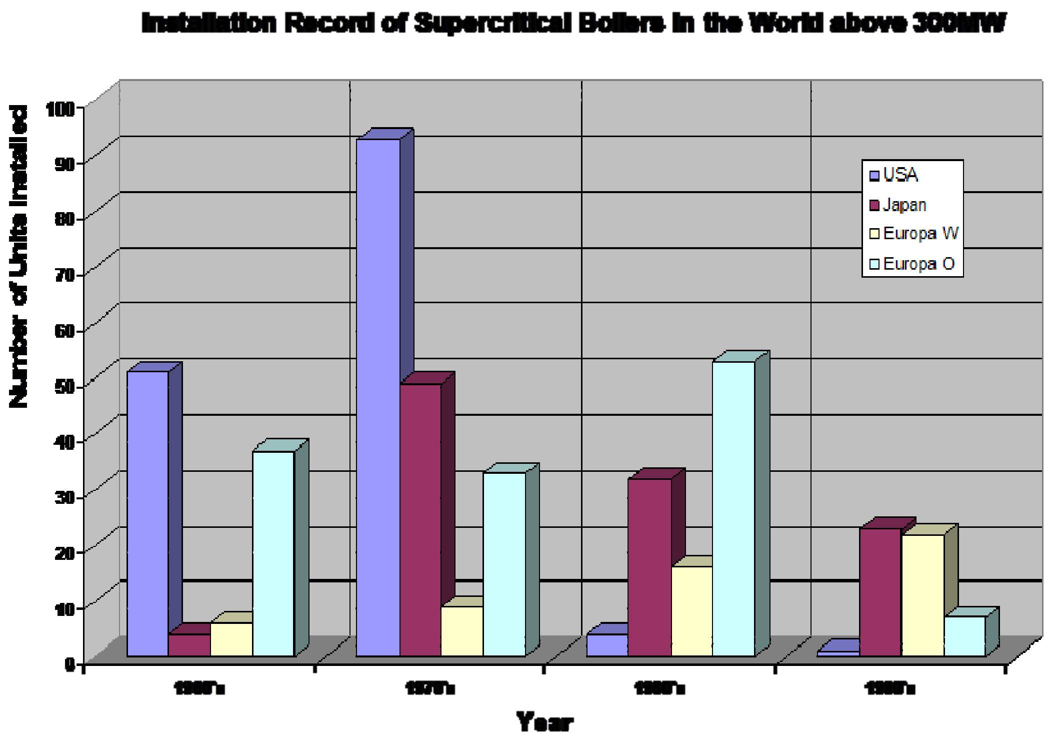


A few examples of the US, German, Japanese and Chinese markets follow to illustrate the key drivers for the technology-related decisions being made.

<u>US Experience</u>

The United States was the leader in designing and manufacturing supercritical and USC plants in the late 1950s and 1960s. The first USC plant in the world was Ohio Power's (now American Electric Power) Philo unit #6 with 125MW output and double reheat steam conditions (31MPa/612^{o}C/565^{o}C/538^{o}C). This was a demonstration project built in 1957. It was followed by the first commercial USC unit at Eddystone plant built in 1959 by Philadelphia Electric; this unit was designed for: 34.5 MPa/650^{o}F/565^{o}C/565^{o}C double reheat steam conditions. Subsequently, in the 1960s and 1970s, US utilities built a total of 155 supercritical units representing 107 GWs of installed capacity; 109 of these units (representing approximately 75 GWs) are coal-fired; the remaining are oil- and gas-fired. Figure 4 shows the number of supercritical units above 300 MWs, which were built in the United States, as well as Japan, Western Europe ("Europe W") and the rest of Europe ("Europe O") over the period 1960-2000.

Figure 4: Installation record of supercritical boilers in the World



Source: Deutsche Babcock

The initial experience was not positive in the United States; reliability problems were experienced related to the high temperature components of the supercritical plants. For example, Eddystone #1 experienced mechanical and metallurgical problems, and its pressure and temperatures were derated to supercritical conditions under which it operates to this day.

The initial reliability problems developed a negative perception among utility executives and many of them started selecting subcritical for their future plants, a decision supported also by a period of low fuel prices. Another factor which contributed significantly to the selection of subcritical, especially in the late 1960s and early 1970s, was that demand for electricity was increasing rapidly and manufacturers did not have adequate time to advance the state of the art or even change previous plant designs. Utilities (pressed to build new plants as soon as possible, a situation similar to the present conditions in India and China) used to order duplicates of previously built plants without any design changes. This resulted in a significant number of subcritical plants built in the late 1960s and 1970s.

Coal-fired plant construction almost came to an abrupt stop after the second oil crisis of 1979, with declining US economy and electricity demand. Since then and until the last 10 years very few coal-fired power plants were built in the United States. This was partly due to the lack of rapidly increasing demand (late 1980s) and partly due to the "rush for natural gas combined cycles" (1990s), which was accelerated by low gas prices and advancements in gas turbine technology. During the last 20 years, less than 5 percent of the new power generating capacity was coal-fired. Also, the coal-fired stations were mostly subcritical with a few exceptions (e.g., the W.H.Zimmer 1,300 MW station which started operating in 1991 and Genesee #3 a 495 MW unit which started operating in 2005 are supercritical).

In summary, the United States put in operation a substantial number of subcritical plants in the 1960s and 1970s, even though supercritical technology was commercial because supercritical had developed a bad reputation (due to low reliability of the first generation plants) and rapidly growing demand necessitated building the plants which were the easier to build within a short time period. However, the US is starting again to build supercritical and USC plants, as fuel prices are relatively high and there is pressure to increase plant efficiencies in response to climate change concerns. According to US DOE, 37 projects are planned representing approximately 25 GWs of installed capacity. Specific plants in various stages of construction or planning include:

- Wisconsin Public Service's Weston #4, a supercritical 530 MW under construction planned for start up in 2008;
- Wisconsin Energy's Elm Road #1 and 2, supercritical 677 MW under construction planned for start up in 2009 and 2010;
- Kansas City Power & Light's Iatan #2, a supercritical 850 MW under construction planned for start up in 2010;
- Xcel Energy's Comanche #3, supercritical 750 MW (24.7 MPa/565^{o}C/593^{o}C) under construction planned for start up in 2009;
- Duke Power's Cliffside #6, a supercritical 900 MW planned for start up in 2011; and
- American Electric Power's Turk plant, ultrasupercritical 600 MW planned to start operation in 2011.

<u>The Experience of Germany and Japan</u>

As Figure 4 shows, Japan started building supercritical plants in the 1970s, and continued in the 1980s and 1990s. Germany, which has most of Western Europe's supercritical units, built them in the 1980s and 1990s. In both countries, economics played a secondary role in the decision to build these units. The most important driver in the development of supercritical technology was the government's commitment to advance the state-of-the-art pulverized coal technology, requiring each new unit to have higher steam conditions and efficiency than the previous one. While this was not legislated, all power companies followed this principle. The government supported the industry (both power plant manufacturers and power generation companies) with funding to carry out research and development. The higher costs of supercritical power plants compared to subcritical were absorbed by the consumers through tariff adjustment (as the market was regulated at that time).

Japan continues this practice of designing new power plants with increasingly higher steam conditions even now under a partially deregulated market. For example, JPower Ltd. (previously called Electric Power Development Corp. (EPDC)) is building Isogo #2, a 600 MW USC plant using higher steam conditions than Isogo #1 which started operating in 2002; unit #1's operating conditions are 25.5MPa/600^{o}C/610^{o}C, while unit #2's 25.5MPa/600^{o}C/625^{o}C.

The situation in Germany is similar. In the 1990s, many old and inefficient units in (what used to be called) East Germany closed down to be replaced by the most modern and efficient plants, after the re-unification of West and East Germany. Examples of such projects are: Schwarze Pumpe (1997/98; 2X800 MW), Niederaussem (1998; 2X1,000 MW), Neurath (2009/10; 2X1,100 MW) and Westfalen (2010/11; 2X800 MW). The plants being built presently continue to expand the technological envelop driven mainly by the need to reduce CO_2 emissions and comply with the Kyoto Protocol.

<u>China's Experience</u>

Presently China has an installed coal-fired capacity of approximately 400 GW which is growing by 50-100 GW per year. Before the 1990s, China utilized subcritical coal-fired plants ranging from a few megawatts (1-10 MW) to standardized 200 MW, 300 MW and 600 MW units. All these power plants were manufactured domestically. The larger units utilized technology obtained through licensing agreements with western suppliers; the technology was made available to all the leading local manufacturers (Harbin Boiler Group, Shanghai Boiler Group and Dongfang Boiler Industrial Group, etc).

China started using supercritical technology in the 1990s with the procurement of 10 units (4X320MW; 4X500MW; and 2X800MW) from Russia. The steam conditions of these units were: 23.5 MPa/540^{o}C/540-570^{o}C. The first plant utilizing western technology was the Shi Dong Kou, commissioned in 1992 and consisting of 2X600 MW units with 25.4 MPa/538^{o}C/565^{o}C steam conditions. The second plant utilizing western technology was the Waigaoqiao plant in Shanghai (next to the Shi Dong Kou), which consists of two 900 MW units with steam conditions: 24.7 MPa/538^{o}C/565^{o}C. The project was financed with a World Bank loan. Since then, many more supercritical units were built and approximately 22 were in operation, as of the end of 2005; more are operating by now.

The first USC plants (Huadian's Zouxian and Huaneng's Yuhuan power plants) started operating in late 2006 (November-December). These units are 1,000MW each with steam conditions: 26.2 MPa/605^{o}C/605^{o}C.

Sixty percent of the new plants that started construction after 2005 and represent a total of 37.8 GW (600 MW each) are supercritical. Also, 60 percent of the future plants are expected to utilize supercritical and USC steam conditions. By the end of 2007, approximately 120 GWs of installed capacity will be utilizing supercritical conditions.

Chinese manufacturers have developed joint ventures and licensing agreements, so the majority of the equipment for supercritical and USC plants is already manufactured in China. More specifically, Shanghai Boiler Works has teamed up with Alstom and Siemens; Harbin Boiler Group works with Mitsubishi; and Dongfang Boiler Industrial Group has a joint venture with Hitachi.

While there is a clear commitment to supercritical technology, subcritical plants, including very small ones (well below 100 MW), continue to be built in China for a variety of reasons:

- Lack of adequate manufacturing capacity for the state-of-the-art supercritical and USC plants to satisfy rapidly increasing demand. The three large Chinese suppliers of power plants (Harbin, Shanghai and Dongfang), which are able to manufacture such plants, cannot satisfy the increasing demand for electricity. Reportedly, they are fully booked for the next three years with all the orders being supercritical.
- It is not practical to close down all manufacturing facilities in China, which have been producing smaller units (up to 300MW) or convert them to manufacture state-of-the-art plants in a short period of time. In fact, some of these facilities, in addition to satisfying domestic demand, are targeting exports to other countries. Typical sizes of coal-fired units being exported are in the 100-300 MW range.

Costs of Pulverized Coal Plants

Presently, capital costs of coal-fired plants (including those equipped with FGD and SCR) in most OECD countries range from \$1,300 to 1,700 per kW. Supercritical plant costs are typically up to 6 percent higher than similar size subcritical plants. USC plants are 5-10 percent more expensive than subcritical plants. Table 5 provides indicative capital costs for pulverized coal power plants equipped with FGD and SCR in the United States from recent (2006-2007) studies.

Table 5: Capital Costs (\$/kW)

Source	Size (MW)	Subcritical	Supercritical	Difference (%)	USC	Difference re. Sub.
DOE (2007)/Bituminous	750	1548	1574	1.7		
EPRI (2007)/Bituminous	600	NA	1290-1800	NA		
EPA (2006)/Bituminous	425	1347	1431	6.2	1529	13.5
EPA (2006)/SubBituminous	425	1387	1473	6.2	1575	13.6

International prices fall in a comparable range. In the last three years, prices of power plant equipment in general (independently of the type of power plant) have increased by up to 25-30 percent and they are mostly in the upper half of the $1,300-1,700/kW range. However, the cost differentials (expressed in percentage) between various types (subcritical, supercritical and USC) are still the same.

It is noteworthy to mention that China and India fall outside the above price range. Typical prices for Chinese-manufactured power plants with FGD units are[12]:

- 300 MW subcritical: $630/kW;
- 600 MW supercritical: $540/kW; and
- 1,000 MW USC: $540/kW.

Prices of power plants in India are between OECD and Chinese prices. For example, 500-660 MW plants (without FGD and SCR) are quoted at approximately $1,000/kW.

The prices reflect the impacts of both steam conditions and economies of scale (impact of size). Also, it is not clear if these prices include full scope construction, guaranteed performance and start-up costs.

Part of the cost differentials between international and Chinese prices can be explained by lower labor costs and the increasing share of domestically manufactured components in China. However, these factors alone do not explain the cost differences fully. Other factors which may have a significant effect too include:

- Exchange rate.
- Pricing of materials which may not follow international prices; China has approximately 1/3 of the worldwide steel production and it is not clear how it allocates this production to the various manufacturing facilities and at what price.
- Also, there is no adequate track record to determine product quality (e.g., long-term reliability and performance).

While the present situation in China does not impact significantly the international and more specifically the Asian markets, some impacts are already apparent:

- It is nearly impossible for international suppliers to compete in China, unless they have joint ventures in the country and produce equipment locally.
- China's manufacturing capacity, especially for the large and more efficient plants, is fully committed to satisfying the domestic demand. However, the manufacturing facilities which produce smaller and lower efficiency plants (for which demand has declined domestically) started exporting them to countries such as Bangladesh, India, Indonesia, Pakistan and African countries. Depending on how the domestic market develops, it is possible that the excess manufacturing capacity would be used for significant exports in the future.

O&M costs are similar for all three pulverized coal types. Table 6 provides typical estimates for a 500 MW unit in the US.

[12] Source: Thermal Power Research Institute and others; foreign exchange rate: 1US$ = 7.3 RMB (Yuan)

Table 6: O&M Costs for a 500 MW Unit ($/kW) in the US

	Subcritical	Supercritical	USC
Fixed O&M ($/kW-yr)	40.5	40.8	41.1
Variable O&M ($/MWh)	1.7	1.65	1.6

Source: EPRI (2004)

When levelized cost of electricity is estimated using the above (international) investment requirements, nearly all studies conclude that the higher efficiency plants are more competitive. The exception is mine-mouth plants which may take advantage of cheap coal, in which case subcritical plants have shown to have a small competitive advantage.

Manufacturers of Pulverized Coal Plants

Subcritical power plants are manufactured by many companies both international and country suppliers. Supercritical plants have multiple suppliers too; the following is a lit of the boiler manufacturers:

- Alstom (France) including Combustion Engineering (USA), EVT (Germany) and Stein (France)
- Ansaldo (Italy)
- Babcock Hitachi (Japan)
- Babcock & Wilcox (USA)
- Doosan Babcock Energy (Republic of Korea)
- Foster Wheeler (USA)
- Ishikawajima-Harima Heavy (IHI of Japan)
- Mitsubishi Heavy Industries (Japan)
- Mitsui Babcock (UK-Japan) including Deutsche Babcock and Steinmuller (Germany)
- Podolsk (Poland)
-

The companies underlined offer USC, too.

Manufacturers of supercritical and USC steam turbines are:

- Alstom (France)
- Ansaldo (Italy)
- Babcock Hitachi (Japan)
- Fuji Electric (Japan)
- General Electric (USA)
- LMZ (Russia)[13]
- Mitsubishi Heavy Industries (Japan)

---

[13] Note the suppliers of approximately 240 supercritical units in the former USSR are not known; around 2000, there were three boiler suppliers: Taganrog (TKZ), Podolsk (ZiO) and Barnaul (BKZ)

- Mitsui Babcock (UK-Japan) including Deutsche Babcock and Steinmuller (Germany)
- Siemens (Germany) including Westinghouse (USA)
- Toshiba (Japan)

Circulating Fluidized Bed Combustion

Fluidized bed combustion is a method of burning coal in a "bed" of (ash and limestone) particles suspended in flowing air. There are two types of fluidized bed designs — bubbling and circulating. Also, there is atmospheric and pressurized variance of the design. Pressurized fluidized bed combustion (PFBC) has been demonstrated in a number of countries, but it experienced operating problems and is not being promoted commercially. Both bubbling and circulating atmospheric fluidized bed combustion units are in operation worldwide, but circulating fluidized bed (CFB) is more common for power generation applications, especially in plants larger than 100 MW. The bubbling version is used mostly for biomass and waste fuels in smaller units (10-50 MW). For this reason, only CFB is discussed in this report.

High-ash fuels, such as lignite, brown coals and Indian coals, are particularly suitable for CFB technology. CFB is considered commercially available up to 300 MW, as demonstrated by hundreds of such boilers operating throughout the world (e.g., Australia, China, Czech Republic, Finland, France, Germany, India, Japan, Poland, Republic of Korea, Sweden, Thailand and the United States). The number of CFB operating units has increased since the late 1980s (when the technology started being commercial) to above 600 units today representing approximately 40,000 MW of installed capacity worldwide. Experience from these units has confirmed performance and emissions targets, high reliability, ability to burn a variety of fuels and costs.[14]

CFB plant efficiencies are similar to pulverized coal plants with FGDs; if FGDs are not needed, CFBs are expected to have lower net plant efficiency than similar size pulverized coal plants. Because most CFB are designed for subcritical steam conditions, their efficiency ranges from 35.0 to 38.0 percent (HHV basis)[15]. One 460 MW supercritical CFB plant in Lagisza, Poland is designed for supercritical conditions with an efficiency about 40 percent.

Most of CFB units in operation today have been manufactured by Alstom and Foster Wheeler. However, there are other smaller suppliers, including manufacturers in China, India, Poland and the Republic of Korea.

Noteworthy developments related to CFB technology are in the following countries:

[14]Palkes, M., Waryasz, R., "Economics and Feasibility of Rankine Cycle Improvements for Coal Fired Power Plants", Final DOE-NETL Report under Cooperative Agreement No. DE-FCP-01NT41222 Prepared by Alstom Power Inc., February, 2004

[15] IEA/Clean Coal Center, Profiles: "Developments in Fluidized Bed Combustion technology", June 2006, PF 06-03

- *China*: There are at least 200 (possibly up to 500) CFB units in operation, ranging in size from 3 MW to 300 MW. The total installed capacity is estimated at 10,000 MW. Approximately 2,500 small bubbling AFBC boilers have also been constructed, but there are no accurate statistics regarding to their operating status. Nevertheless, China is pursuing development and localization of CFB technology aggressively as demonstrated (among others) by the construction of the 300 MW Baima plant and a program to develop an 800 MW CFB design.
- *The Czech Republic* has at least 28 CFB units in operation ranging in capacity from 28 MWs to 120 MW (average: 50 MW). The total installed CFB capacity is 1,400 MW. Developments in this country, as well as countries such as Germany, Poland and Turkey, are most relevant to India as these countries utilize low rank coals.
- *Germany* has 45 units in operation ranging in size from 6 MW to 100 MW with an average of 40 MW. Total installed CFB capacity is 1,800 MW.
- *Poland* has 25 CFB units in operation with the smallest unit being 25 MW and the largest (Lagisza) 460 MW. The total installed CFB capacity in Poland is 3,310 MW. The Lagisza plant (presently in start-up) is the world's largest and first supercritical CFB unit.
- *The United States* has approximately 8,800 MW of CFB installed capacity, consisting of 145 units of 3 to 300 MW each.

All sizes mentioned above refer to single CFB boilers. However, multiple CFB boilers can be combined to develop plants larger than 300-400 MW. For example, Vietnam has an aggressive program to build several 1,000 MW CFB plants, each one of them consisting of 4X250MW CFB boilers and 2X500 MW steam turbines.

With regard to future developments, Alstom and Foster Wheeler have 600 MW supercritical designs which they offer commercially. Foster Wheeler, in partnership with several European companies, is looking further into a state-of-the-art 800 MW design with USC steam conditions (30 MPa and 600^{o}C). Also, China has started a program aimed at developing a supercritical 800 MW CFB design.

The main drivers for the utilization of CFB are the technology's ability to use low quality fuels or fuels that are difficult to burn in other types of boilers, and the need to reduce SO_2 emissions. For example, CFB units can burn anthracite, a fuel which is very difficult to burn in a conventional pulverized coal boiler. Also, CFB units can burn other lower rank coals with high ash and sulfur content for which the economics (see below) are favorable compared to pulverized coal with FGD.

Because CFB boilers can be manufactured at the same facilities as those for pulverized coal boilers, the technology has been introduced and accepted easily in developing countries with boiler manufacturing capacity.

Costs of CFB Plants

The capital costs of CFB plants are affected by many site-specific factors, such as coal properties, environmental regulations, sourcing of the key components, and geophysical characteristics of the construction site. Table 7 provides a sample of the relevant capital costs available for various locations.

As mentioned in the case of pulverized coal plants, capital costs of power plants in general have increased substantially in the last 2-3 years worldwide. It is estimated that CFB costs are about the same with pulverized coal plants with FGD units, 1,200-1,500/kW.

Table 7: Sample of CFB Capital Cost Estimates

Location	Size (MW)	Capital Costs ($/kW)	Source
Elbistan, Turkey	250	1100	World Bank, Turkey EER Report/Task 2
Jacksonville, FL, USA	2X300	1050	Coal Age Magazine, Nov 2002
Generic, Europe	150	1273	Eurostat (Les Echos Group), 2003[16]
Generic, USA	200	1304	Alstom (2003)[17]
Generic, USA	664 (supercritical)	1038	Alstom (2003)[18]
Average		1153	

Source: World Bank, "Technical and Economic Assessment of Grid, Mini-Grid and Off-Grade Electrification Technologies", September, 2006

Typical O&M values for a coal-fired CFB plants are provided in Table 8.

Table 8: CFB Operating and Maintenance Costs in the US

Items	Costs
Fixed-O&M Cost ($/kW-yr)	42.2
Variable-O&M Cost ($/MWh)	3.4

Source: World Bank, "Technical and Economic Assessment of Grid, Mini-Grid and Off-Grade Electrification Technologies", September, 2006

Integrated Gasification Combined Cycle

Integrated gasification combined cycle (IGCC) power generation is a technology in which coal is gasified with either oxygen or air, and the resulting synthesis gas (or syngas, consisting of hydrogen and carbon monoxide), is cooled, cleaned and fired in a gas turbine. The hot exhaust from the gas turbine passes through a heat recovery steam

[16] Source: World Energy Council, "Performance of Generating Plant 2004", Section 3
[17] Source: Marion, J., Bozzuto, C., Nsakala, N., Liljedahl, G., "Evaluation of Advanced Coal Combustion & Gasification Power Plants with Greenhouse Gas Emission Control", Topical Phase-I, DOE-NETL Report under Cooperative Agreement No. DE-FC26-01NT41146 Prepared by Alstom Power Inc., May 15, 2003
[18] Source: Palkes, M., Waryasz, R., "Economics and Feasibility of Rankine Cycle Improvements for Coal Fired Power Plants", Final DOE-NETL Report under Cooperative Agreement No. DE-FCP-01NT41222 Prepared by Alstom Power Inc., February, 2004

generator (HRSG) where it produces steam that drives a steam turbine. Power is produced from both the gas and steam turbine-generators. By removing the emissions-forming constituents from syngas prior to its combustion, an IGCC power plant can meet extremely stringent emission standards.

There are three major types of gasification systems in use today: moving bed, fluidized bed, and entrained flow. All three systems use pressurized gasification (20 to 40 bar), which is preferable to avoid auxiliary power losses for syngas compression. Most gasification processes currently in use or planned are oxygen-blown, which provides potential advantages if sequestration of carbon dioxide emissions is a future possibility.

IGCC achieves very low emissions, especially with regard to particulates, SO_2 and NOx. For satisfactory operation of the gas turbines, very low levels of particulates in the syngas are required. More than 98 percent of the SO_2 could be removed and NOx emissions typically fall in the 15-20 parts-per-million (ppm) range.

IGCC has the potential to achieve higher efficiency than pulverized coal plants. Large IGCC plants (400-700 MW) are projected to have an efficiency of 43-48 percent (HHV), compared to 43-46 percent (HHV) for advanced USC plants. However, presently IGCC efficiency is similar to supercritical plants, 38-41 percent (HHV).

Worldwide, there are 138 operating plants with 417 gasifiers representing a total capacity equivalent to 56 GWth. Fifty-five percent of the plants in operation use coal and 32 percent petroleum residues. These plants produce 44 percent chemicals, 30 percent syngas (used for production of ammonia, pertilizers and other chemicals), and 18 percent power. Table 9 shows the IGCC power plants in operation. Among them, only Demkolec, Wabash and Tampa are burning 100 percent coal; the Puertollano IGCC burns both coal and petcoke; the others burn mainly refinery bottoms.

Table 9: Large IGCCs in Operation

	Gasification Technology	MW (Gross)	Startup Date
SEP/Demkolec, Buggenum, The Netherlands	Shell	253	Early 1994
Wabash River, Indiana, USA	E-gas	296	10/1995
Tampa Electric, Florida, USA	GE (Texaco)	312	9/1996
ELCOGAS, Puertollano, Spain	Krupp-Uhde Prenflo	335	12/1997
ISAB Energy, Sicily, Italy	GE (Texaco)	512	2001
Sarlux, Sardinia, Italy	GE (Texaco)	548	8/2000
API Energia, Falconara, Italy	GE (Texaco)	280	2001
Exxon Chemicals, Singapore	GE (Texaco)	160	2001
Valero (Premcor), Delaware, USA	GE (Texaco)	160	2003
Nippon Refining, Negishi, Japan	GE (Texaco)	342	2003
Eni Sannazzaro, AGP, Italy	Shell	250	2006

It is noteworthy that there are no large IGCC units utilizing fluidized bed gasification technology which is suitable for Indian coals. The largest fluidized bed gasifiers are U-

Gas type (offered by Gas Technology Institute, GTI) designed to process 150 tons of coal per day and they are operating in China. All other fluidized bed gasification technologies are still in pilot stages: KRW (Kellogg Rust Westinghouse) at15 tpd and KBR (Kellogg Brown and Root) Transport at 65 tpd. The KRW technology was used at Sierra Pacific's Pinon Pine demonstration project, 100 MW IGCC plant, but this plant experienced problems and was shut down.

Commercial Availability and Suppliers of IGCC

The following gasification technologies are considered commercially available for power generation applications:

- General Electric: Texaco, entrained flow gasifier;
- Shell: Entrained flow gasifier;
- ConocoPhillips: E-Gas entrained flow; and
- Mitsubishi: air-blown entrained flow gasifier.

Lurgi (moving bed gasifier) and GTI's U-Gas (fluidized bed gasifier) have experience in large plants producing syngas and chemicals, but not power generation. Also, Siemens has extensive experience providing gas turbines for large IGCC plants and recently acquired its own gasification technology. All the remaining technologies are at various stages of development, but do not have large scale plants (above 100 MW) in operation.

Costs of IGCC

Capital cost estimates for IGCC plants, mostly entrained flow utilizing bituminous coal, are 10 to 30 percent higher than similar size pulverized coal plants. The most recent cost estimates in the industry are those published by US DOE in mid-2007. Their capital-cost estimates for a 750 MW plant using bituminous coal are:

- Subcritical: $1,548/kW
- Supercritical: $1,574/kW
- IGCC: $1,841/Kw

The cost differential between these same technologies utilizing subbituminous coal and lignite is even wider, as projected by the same study. More detailed information, including cost of electricity (COE) with and without Carbon Capture and Sequestration (CCS), on the three main gasification types (GE, E-Gas and Shell) are shown in Table 10.

CCS is not required presently, but it is being considered seriously by many countries. There are a number of outstanding issues (technical, legal, regulatory and competitiveness) which make it difficult to assess its impact on the competitiveness of the power generation technologies. However, preliminary estimates indicate that IGCC will be impacted less than pulverized coal. More detail description of CCS is provided in Appendix 1.

Table 10: Comparison between three IGCC technologies
(Fuel cost: 1.80 $/MBtu)

Performance Results

	GE Energy		**E-Gas**		**Shell**	
CO_2 Capture	**NO**	**YES**	**NO**	**YES**	**NO**	**YES**
Gross Power (MW)	**770**	**745**	**742**	**694**	**748**	**693**
Auxiliary Power (MW)						
Base Plant Load	23	23	25	26	21	19
Air Separation Unit	103	121	91	109	90	113
Gas Cleanup/CO_2 Capture	4	18	3	15	1	16
CO_2 Compression	-	27	-	26	-	28
Total Aux. Power (MW)	130	189	119	176	112	176
Net Power (MW)	640	556	623	518	636	517
Heat Rate (Btu/kWh)	8,922	10,505	8,681	10,757	8,304	10,674
Efficiency (HHV)	**38.2**	**32.5**	**39.3**	**31.7**	**41.1**	**32.0**

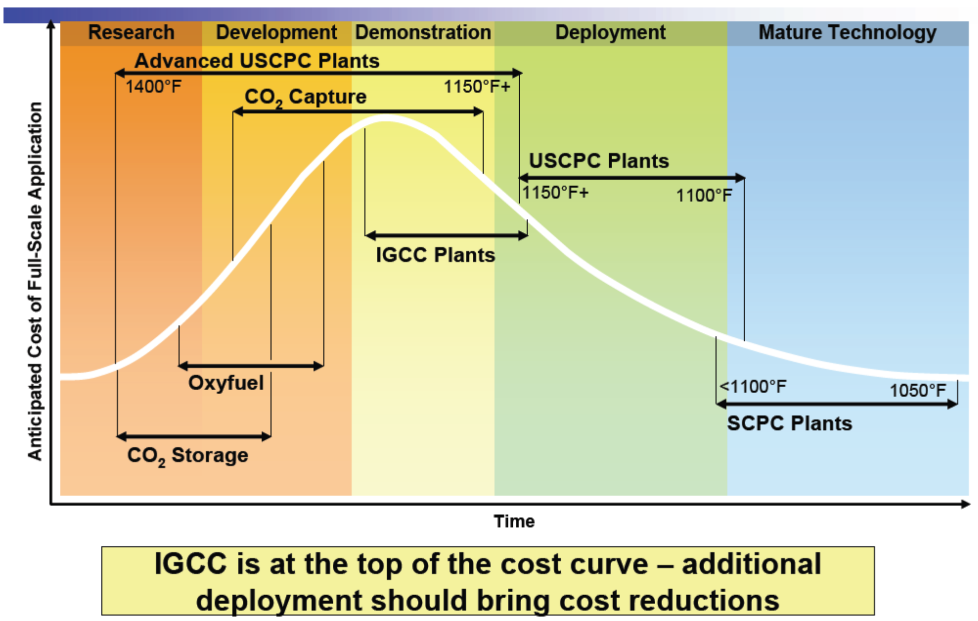
Economic Results

	GE Energy		**E-Gas**		**Shell**	
CO_2 Capture	**NO**	**YES**	**NO**	**YES**	**NO**	**YES**
Plant Cost ($/kWe)						
Base Plant	1,323	1,566	1,272	1,592	1,522	1,817
Air Separation Unit	287	342	264	329	256	336
Gas Cleanup/CO_2 Capture	203	414	197	441	199	445
CO_2 Compression	-	68	-	69	-	70
Total Plant Cost ($/kWe)	**1,813**	**2,390**	**1,733**	**2,431**	**1,977**	**2,668**
Capital COE (¢/kWh)	4.53	5.97	4.33	6.07	4.94	6.66
Variable COE (¢/kWh)	3.27	3.93	3.20	4.09	3.11	3.97
CO_2 TS&M Costs (¢/kWh)	0.00	0.39	0.00	0.41	0.00	0.41
Total COE (¢/kWh)	**7.80**	**10.29**	**7.53**	**10.57**	**8.05**	**11.04**
Increase in COE (%)	**-**	**32**	**-**	**40**	**-**	**37**
$/tonne CO_2 Avoided	-	35	-	45	-	46

Source: US DOE Baseline Study on for Fossil Energy Plants, 2007
COE: Cost of Electricity; TS&M: Transport, Storage & Monitoring

As with every emerging technology, it is expected that IGCC costs will decline with more plants being implemented, as the industry gains experience, simplifies the IGCC plant design and takes cost-cutting measures. Figure 5 shows a typical technology "learning curve" illustrating that IGCC is presently in the demonstration stage and cost reductions should be expected.

Figure 5: Technology Development Curve for IGCC



Source: EPRI presentation from www. Gasification.org

Technological developments which are expected to be achieved by the next generation of IGCC projects and contribute to such cost reductions include:

- Utilization of dry coal feed system instead of slurry;
- "Warm" or hot gas clean-up systems;
- Improvement of gasifier refractory properties, resulting in longer life cycle;
- Ion transport membranes for air separation;
- Gas turbine inlet chilling where appropriate and effective;
- Advanced syngas turbines to increase efficiency and reduce NOx emissions;
- Improved reliability of key components and the overall system in general; and
- Reduced use of water.

Underground Gassification

Instead of gasifying coal to produce syngas after coal has been mined, an alternative is to gasify coal in-situ underground. As with conventional IGCC, CO_2 capture and storage can be used following underground gasification and the water shift reaction. This technology, still at early stages of development, involves:

- Injection of oxidants (water/air or water and oxygen) into the cavity which contains coal; and
- Extraction of the products, usually syngas containing hydrogen, carbon monoxide and methane.

Two technologies are being developed:

- *Vertical wells method* developed by the Former USSR and
- *Coal seams method* developed in China, Europe and North America.

The former was tested in numerous sites in ex-USSR since the late 1940s to 1989 utilizing all types of coal (bituminous, sub-bituminous and lignite). Two plants are still in operation, one at Angren, Uzbekistan and the other in Siberia. The Angren plant is operating for about 40 years and produces gas which is burned in boilers generating 50-150 MWe. Also, the same technology has been tested on shallow high-ash coals at Chinchilla, Australia in 1999-2003. A 40 MW power plant is being considered as the next step in Australia after CSIRO (the Australian Government research center) concluded a study in 2003.

Underground coal gasification (UCG) was tested also in a coal mine in Hokkaido, Japan in the 1960s. However, there was no follow-up as Japan's domestic coal production was reduced to nearly zero and the country started relying on imported coal and liquefied natural gas (LNG).

The European Working Group on UCG supported testing of the technology in a Spanish mine, which were successfully completed in the period 1992 - 1999. Subsequently, the UK Department of Trade, Industry & Technology carried out a pre-feasibility study (Jan 2000) and evaluated suitable sites. The results of these studies are summarized in a report entitled "*Review of the feasibility of underground coal gasification in the UK*", which was issued in September 2004. Recommendations are made for large scale demonstration as a next step, but no such project has been implemented yet.

Eskom Holdings Ltd. of South Africa has commissioned a 6-MWth UCG pilot plant at the Majuba coalfield in Mpumalanga, South Africa. This is Africa's first UCG technology application. The first flaring of gas from the UCG pilot project occurred on Jan. 20, 2007.

China has the largest on-going UCG program. Since the 1980s, 16 trials have been completed mainly on abandoned mines. The focus on the Chinese efforts is production of ammonia and hydrogen, not electricity. Key organizations involved are: China University and Technology of Beijing and the XinAo Group. The latter is planning to test underground gasification (pilot scale) in a sub-bituminous coal mine the second half of 2007.

A Workshop on Underground Coal Gasification was held in Kolkata, India on November 12-15, 2006. The presentations, including status and experiences in countries such as Australia, Canada, China and India, can be found in the following web site:

http://www.fossil.energy.gov/international/International_Partners/November_2006_UCG_Meeting.html

More information on UCG can be found in the following websites:

- http://www.berr.gov.uk/files/file18660.pdf
- http://www.worldcoal.org/assets_cm/files/PDF/ecoal_ucg_article_oct06.pdf
- http://www.coal-ucg.com/
- http://www.ucgp.com/
- http://www.fossil.energy.gov/international/Publications/cwg_june07_friedman.pdf
- http://www.coal.gov.uk/resources/cleanercoaltechnologies/ucgintro.cfm
- http://www.coal.gov.uk/media//44435/ucgintroductiondti.pdf
- http://www.ucgengineering.com/
- https://eed.llnl.gov/co2/11.php
- http://www.coal.gov.uk/resources/cleanercoaltechnologies/ucgintro.cfm
- http://www.lincenergy.com.au/ucg.php

Biomass Co-firing

Co-firing biomass has been demonstrated and used in all types of boilers, pulverized coal, CFB, cyclone and stokers ranging from 30 to 700 MWs. Biomass co-firing has been used extensively in the Scandinavian countries, mostly in stoker and CFB boilers of relatively small sizes (up to 50 MWs). In the 1990s, many power plants demonstrated this option in Europe, Japan and United States, and then proceeded to use it commercially. In recent years with the need to reduce greenhouse gas emissions and meet Kyoto requirements in some countries, there is renewed interest in biomass co-firing on the basis that biomass is "CO2-neutral".

Biomass may include switchgrass, sawdust, wood wastes, municipal solid wastes and other waste fuels. In most cases, biomass is limited to a maximum of 15 percent of the total plant input. The boilers could be designed specifically to accommodate biomass combustion or existing boilers could be modified; the industry has experience with both.

In the US, biomass co-firing tests we carried out in boilers of various types as shown in Table 11. Numerous stations in Europe and Japan have tested biomass co-firing too. Also, many are planning to use co-firing on a regular basis. For example, Chubu Electric Power Co. of Japan is adding co-firing capability in its Hekinan station (3X700 MW and 2X1,000MW units) and is planning to burn 2 percent biomass (wood wastes) starting in 2009.

Power plants which have long experience with biomass co-firing are:

- Lakeland unit #3, Florida, USA: a 364 MW wall-fired unit burning coal and up to 8 percent of the heat input municipal solid wastes (MSW). This unit was designed for co-firing and operates in this mode since 1983.
- Dong Energy of Denmark co-fires biomass with coal, with biomass contributing about 7 percent of the total heat input.

Table 11: Utility Tests of Biomass Co-firing in the US

Utility (Plant)	Boiler Size & Type	Biomass Heat Input	Biomass Type	Average Moisture	Coal Type	Biomass Feeding
Allegheny (Allbright)	150 MW Tangential	5-10%	Sawdust	~40%	Bituminous	Separate injection
Allegheny (Allbright)	188 MW Cyclone	5-10%	Sawdust	~40%	Bituminous	Blending
GPU Seward	32 MW Wall-fired	10%	Sawdust	44%	Bituminous	Separate injection
Madison Gas & Electric (Blount Str)	50 MW Wall-fired	10%	Switchgrass	10%	Bituminous	Separate injection
NIPSCo (Michigan City)	469 MW Cyclone	6.5%	Municipal Solid Waste	30%	SubBituminous	Blending
NIPSCo (Bailly)	194 MW Cyclone	5-10%	Wood waste	14%	Bituminous	Blending
NYSEG (Greenidge)	108 MW Tangential	10%	Wood waste	30%	Bituminous	Separate injection
TVA (Allen)	272 MW Cyclone	10%	Sawdust	44%	Western Bituminous	Blending
TVA (Colbert)	190 MW Wall-fired	1.5%	Sawdust	44%	Bituminous	Blending

Source: National Energy Technology Laboratory, US Department of Energy

The technical feasibility of this option is not an issue. Common issues associated with it are:

- Logistics associated with biomass collection and transportation; unless biomass can be obtained from 1-2 sources, it is difficult to arrange collection.
- Biomass prices may be high or may increase after the co-firing project is implemented.
- Power companies avoid modifying their most efficient new power plants considering that co-firing may increase the probability of reliability problems. The most common concerns are failures of the biomass feed system and potential corrosion impacts on the boiler.

The economics of this option are very site-specific. Adding biomass co-firing capability in a new boiler or retrofitting a cyclone or stoker boiler is estimated to cost up to $50/kW. Retrofitting an existing pulverized coal or CFB boiler may cost $150-300/kW[19].

3. Implications for India: Preliminary Observations and Recommendations

Present Situation in India

India has 110 billion tons[20] of recoverable coal reserves[21]. At the annual production rate of 440 million tons, this resource is expected to last approximately 230 years. While this is a sizeable energy resource, the quality of the coal is very poor characterized by high percentage of ash (frequently reaching the 40-50 percent range). In addition to the problems the ash is causing on the power plant equipment due to its abrasive nature (due to high concentration of silicon), transporting such high amount of inert material over long distances is not economic and disposal of the ash close to the power plant is a major issue.

As of the end of 2006, India had an installed power generating capacity of 128 GW consisting of 53 percent coal, 26 percent hydro, 11 percent natural gas, 3 percent nuclear, 2 percent oil and the remaining 5 percent renewables. In 2006, coal contributed 64 percent of the power generation of the country.

Nearly all the coal-fired plants in India are subcritical pulverized coal plants. Standardized designs have been used with the following plant sizes: 60 MW, 110/125 MW, 200/210/250 MW and 500 MW. As the Central Electricity Authority (CEA) states[22] *"200/210/250 MW and 500 MW units form the backbone of the Indian power industry and together constitute about 60% of the total thermal capacity"*. Technology for these plants was originally acquired from the Czech Republic and Russia, and, in the 1970s, from Combustion Engineering Inc. of the United States (presently part of Alstom). In general, India has made significant progress in manufacturing coal-fired power plants. Its manufacturing facilities are state of the art and the organizations involved have demonstrated excellent expertise and achieved significant technological advancements. Also, the industry has addressed successfully the issues associated with the erosive nature of the coal and the high amount of ash.

Efficiency of existing power plants

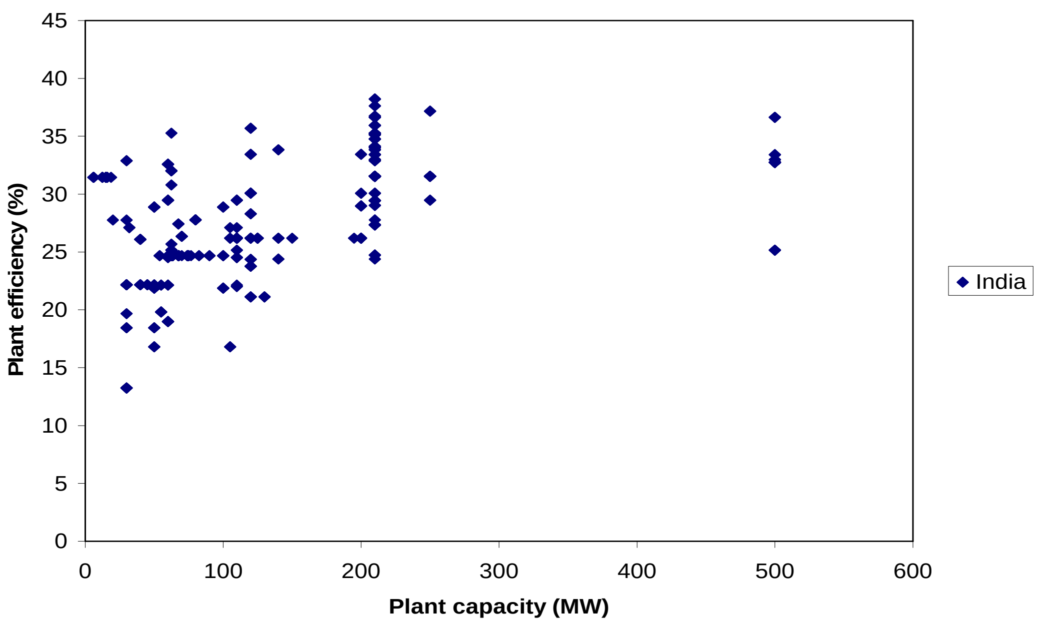
Existing power plants in India have low efficiencies relative to OECD countries. Figure 6 shows the efficiency of power plants in India as reported by the Utility Data Institute (UDI). While there are a few plants in the 35-40 percent range, most of them have an

---

[19] Source: National Renewable Energy Laboratory, "*Biomass cofiring: A renewable alternative for utilities*", DOE/GO-1020000-1055, June 2000
[20] Short tons
[21] Source: US EIA, file:/V:PRJ\NewCABs\V6\India\Full.html
[22] CEA, "*Report of the Committee to recommend next higher size of coal-fired thermal power stations*", November, 2003

efficiency ranging from 20 to 30 percent. For comparison purposes, the average efficiency in OECD countries is 36 percent (HHV-basis); the United States averages 34–35 percent (HHV-basis). New power plants built in OECD countries have much higher efficiency (37-42 percent HHV-basis).

Figure 6: Plant Efficiency of Indian Power Plants, 2005 (HHV-basis)



Source: Platts UDI database (2005)

Here it is important to clarify why these differences exist. "Design plant efficiency" is impacted by many different factors, with the most important of them being: coal characteristics, ambient conditions (cooling water temperature and pressure) and power plant design (mainly steam temperature and pressure at the inlet of the steam turbine, as well as stack temperature). Actual plant efficiency may be lower than "design efficiency", impacted by the operating condition of the plant which in turn is affected by the operating and maintenance (O&M) practices.

Coal characteristics (especially moisture content) have a significant impact on plant efficiency. For example, the EPDC/NTPC study on adoption of supercritical technology in India[23] estimates that for the same plant design and ambient conditions, Indian coal has approximately 1.1 percentage point lower efficiency than imported coal.

Also, the sulfur content of the coal affects the minimum stack temperature for which the plant can be designed. In this respect, Indian coal has an advantage because of its lower sulfur content. For example, the above India-specific references (Mott MacDonald and

---

[23] Electric Power Development Corp of Japan, " Adoption of supercritical technology for Sipat super thermal power plant", January 1999 (Table 3-3-6)

EPDC/NTPC reports) use 125°C as the stack temperature for India, while the US DOE's "Cost and performance baseline for fossil energy plants" study[24] uses 132°C stack temperature for the US. In fact, the stack temperature in the US is often as high as 150°C. This difference results in half to one percentage point higher efficiency for the Indian power plants.

Ambient conditions, especially ambient temperature, humidity and condensing pressure could have a significant impact on plant efficiency, too. Comparing the above India-specific references (Mott MacDonald and EPDC/NTPC reports) with US DOE study, it is concluded that condensing pressure and relative humidity are similar, but ambient temperature is higher in India:

- Condensing pressure used in these studies is about the same; 77 mmHg in India and 75 mmHg in the US;
- 60 percent relative humidity is used in both countries.
- Ambient temperatures: the US DOE report uses 11°C, while the Mott Macdonald report uses 27°C for India.

Of course, it could be argued that the actual ambient conditions in India differ more than the above references suggest. In general, it is estimated that ***the overall impact of coal characteristics, ambient temperatures and stack temperature in India results in 1.0 - 1.5 percentage points lower efficiency compared to a similar design plant in the US.*** This means that if the reference subcritical plant in the US has an efficiency of 36.8 percent (HHVnet), a similar design plant in India burning Indian coal should be expected to have an efficiency of 35.3 to 35.8 percent. This is consistent with reports from power plants in India such as IB Valley Units I and II and NTPC's Farakka plant, which have actual efficiencies in the 36.4-37.7 percent HHVgross range (roughly 34.5-35.8 percent HHVnet). So, Indian plants are in the lower end of the efficiency range provided in Table 1 mainly due to coal characteristics and ambient conditions, but they are within the range nevertheless.

Power plant design conditions, especially steam temperatures and pressures at the inlet of the steam turbine, affect the plant efficiency. Appendix 2 shows the impact of steam conditions on plant efficiency. In India, the most commonly used design is the 500 MW plant utilizing subcritical steam conditions (16.9 MPa/538°C/538°C), as documented by the following references:

- Central Electricity Authority, " Report of the Committee to recommend next higher size of coal-fired thermal power stations", November, 2003
- Mott MacDonald, "India' Ultra Mega Power Projects/Exploring the use of carbon financing", October 2006
- Electric Power Development Corp of Japan, "Adoption of supercritical technology for Sipat super thermal power plant", January 1999.

[24] DOE/NETC-2007/1281, May 2007

Higher reheat temperature (565°C) has been used in several countries including India, but it is not considered a typical design condition for subcritical plants, as most organizations prefer to utilize such temperature in supercritical designs. In India, there are eight such plants operating.

Smaller power plants (e.g., 60-250 MW) are usually designed for lower steam conditions resulting in lower efficiencies. India has many such plants bringing the average plant efficiency of the power system down.

The *actual efficiency* of the power plants is also impacted by:

- Deteriorating or changing coal quality (relative to the original design) over time with adverse effects on plant performance; and
- Deteriorating plant operating conditions mainly due to inadequate maintenance practices and O&M budget.

As a result, efficiencies of 20 percent or even lower have been recorded in many plants in India. In an attempt to improve operation and maintenance (O&M) practices, the Government of India has implemented a program, "Partnership in Excellence", in which better-performing power plants provide assistance to others to enhance plant performance and availability.

In general, the efficiency of many existing power plants could increase by 2-5 percentage points, which represents 6-15 percent reduction in fuel use and CO_2 emissions for the same power generation. Part of this efficiency improvement is expected to be achieved through the R&M plans of the Government (part of the 11th 5-year Plan). However, the R&M plans are usually focusing on life extension (reliability and recovery of lost capacity) and to a lesser extent efficiency improvement. Efficiency is improved as a result of R&M program, but achieving the full efficiency improvement potential would require more investment.

<u>Clean Coal Technologies in India</u>

Supercritical plants are being introduced at unit sizes of 660 MW and 800 MW. Six 660 MW units are under construction at Sipat and North Karanpura plants. Also, supercritical plants have been specified for five ultra-megapower plants (4,000 MW each) which have received approval and are proceeding to be implemented.

CEA's guidelines on the introduction of large supercritical plants[25] are appropriate and clear. CEA recommends that 800-1,000 MW supercritical plants are utilized with steam conditions in the 565°C to 593°C range or even higher depending on site-specific techno-economic considerations.

[25] CEA, "*Report of the Committee to recommend next higher size of coal-fired thermal power stations*", November, 2003

In addition to pulverized coal plants, CFB technology has been used in India. Low rank coal such as India's is a most suitable fuel for CFB boilers. India has started using the technology successfully. Reportedly, there are more than 36 CFB units in operation representing 1,200 MW of installed capacity; most of them are relatively small (2-40 MW) with the largest unit being 136 MW. Also, two 250 MW lignite-fired CFB units are under construction by BHEL.

India has been doing research on IGCC technology. A comprehensive study funded by US AID was completed in 2006 assessing the feasibility of using IGCC in India. This study recommends as a next step a demonstration project of approximately 100 MW utilizing fluidized bed gasification technology. GTI's U-Gas technology was identified as most suitable. BHEL is developing its own fluidized bed gasification technology at a 6.2 MW pilot plant in Trichy, India, which could be also a candidate for the demonstration at 100 MW scale size.

Underground gasification is being explored in India, too. Organizations such as Coal India Ltd., GAIL, ONGC and Reliant Industries Ltd. are surveying sites to test the technology. The Mehsana and Gondwana coal producing areas have been identified as most suitable. In parallel, R&D is carried out in various universities and institutes.

Finally, it is important to mention that steps are taken to utilize more washed coal. The Ministry of Environment and Forest requires that coal shipped more than 1,000 km from the mine should be washed and have less than 34 percent ash. Also, Coal India announced its decision to wash the coal in all new coal mines.[26] As a result, it is projected that coal washing will reach 55 million tons this year (2007) and 163 million tons by 2012.[27] This would certainly reduce transportation costs and improve plant reliability and potentially efficiency. The overall cost-effectiveness of coal washing requires site-specific assessment as it is impacted significantly by factors such as the characteristics of the coal (not all coals are washed easily), the distance between the mine and the plant and the design of the plant. India should carry out an integrated analysis which includes coal mining, coal transport and energy conversion (power plants), and addresses the cost-effectiveness of options such as upstream coal beneficiation (cleaning) and clean coal conversion technologies in an integrated manner.

Towards A Lower Carbon Power Sector Strategy

The strategy for low carbon growth of India's power sector will need to be responsive to the rapidly growing demand, fuel efficient, minimizing both local and global pollution, socially responsive and flexible, and evolving over time as circumstances change. On power generation, the primary objective of this strategy will need to be rapid expansion to respond to growing demand and the needs to close the supply-demand gap. The strategy will need to take into account a range of factors such as cost-effectiveness,

[26] *Coal Age Magazine*, 2007, "(MISC) NEWS," (May), p. 8.
[27] Badal Sanyal, 2007, "Coal India's profits for 2006–07 may dip," *The Hindu Business Line* (March 15), available at http://www.thehindubusinessline.com/2007/03/15/18hdline.htm.

secure access to energy resources (indigenous and imported), speed of implementation (influenced by land, water, and other social and environmental factors, as well as the appetite of strategic and financial investors), and broader political and strategic considerations.

The Low-carbon Growth Strategy study carried out jointly by the Government of India and the World Bank should consider analyzing the following options.

- *An integrated coal chain analysis should be carried out including assessment of the coal resource, potential for beneficiation (coal cleaning), transport costs and linkage to clean coal conversion technologies.* Coal washing is being promoted already, but a more thorough evaluation is needed in the context of the complete coal chain and the need to reduce carbon intensity. Also, a more detailed assessment is needed of the relationship between coal quality (coal grade C, D and E) and the power generation technologies. The result will be a clean coal strategy for coal mining and coal-based power generation, and specific policies may emerge, some of which could be new and others refinements of existing regulations on coal washing (cleaning) and power generation technology initiatives.
- *Rehabilitation of existing power plants should be expanded to focus more on efficiency improvement.* The Government's Renovation and Modernization ("R&M") Program is expected to result in some efficiency improvements, in addition to life extension and reliability improvement which are the primary objectives. However, this program faces barriers, especially related to a lack of funding and interest from major suppliers. Some of the old plants should retire, others be rehabilitated and other be replaced with new state-of-the-art units. The Government has identified the units which belong in each of these three categories and is implementing its refined strategy. If additional funds can be mobilized, scaling up of the R&M program could results in higher plant efficiency improvement. This could be accomplished through utilization of carbon financing and other innovative financing mechanisms. Also, a capacity-building program is needed to assist power companies in planning and implementing R&M programs, as well as strengthen their capacity to operate and maintain their plants utilizing modern O&M management practices such as Reliability-Centered Maintenance, Predictive Maintenance, etc.
- *India introduction of high efficiency supercritical power plants both in new power generation facilities and replacement of old inefficient plants is appropriate.* The official plans include utilization of supercritical plants and guidelines have been provided by CEA regarding the size and design of the new power plants. The target to have 70 percent of the new power plants to be 800 - 1,000MW supercritical units during the 12th 5-year Plan is appropriate. However, higher steam conditions could be used progressively, as the industry gains experience with supercritical plants.

For example, the 24.7MPa/565^{o}C/565^{o}C design could be utilized for a number of units (e.g., ten); then, the following group of units may use 24.7MPa/565^{o}C/593^{o}C, followed by 24.7MPa/593^{o}C/593^{o}C, 24.7MPa/565^{o}C/565^{o}C, 27MPa/593^{o}C/610^{o}C, etc. It is recognized that there are barriers to such a program, including higher investment requirements, limited local manufacturing capacity and perceived risks associated with the higher steam conditions. However, these barriers could be removed through carbon financing instruments, potential incentives provided by the government, joint ventures between local and international suppliers, and awareness-raising about the actual experience of high efficiency power plants in countries such as China, Europe and Japan. A number of incentives are being discussed in India, including potential for discounted loans (e.g., lower interest by 0.5 percentage point), preferential coal allocation, assurance that potential carbon credit revenues will flow back to the plant owners, priority power plant dispatching, etc. Also, a capacity-building program could need to accompany the introduction of supercritical technology to make sure that plant operators and plant engineers are well-trained to operate and maintain such plants.

- While supercritical and ultra-supercritical plants are introduced, it is realistic to expect that *subcritical plants will continue being manufactured and used*. Shorter lead times for these plants, capacity to produce them by local manufacturers and familiarity by the electric utilities of India are factors making them attractive, at least for the short-term (next 10 years). *However, these plants should be as large as possible (e.g., 500 MW) and be designed with high efficiency in mind, preferably with steam conditions: 16.9 MPa/538^{o}C/565^{o}C.*
- *Potential deployment of larger CFB units:* CFB technology is well suited to Indian coal characteristics, but presently is not competitive against pulverized coal plants, as long as no SO2 control is required in India. If and when SO2 control will be required, CFB may become competitive especially for lignite. In the latter case, India may take advantage of future developments in other countries, where CFB is being scaled up to sizes of 500-800 MW units and is likely to utilize supercritical (and eventually USC) steam conditions. In the mean time, *smaller size CFB plants (20-250 MW) could be used burning low grade fuels, such as lignite and coal washing rejects which are difficult to burn in a conventional pulverized coal plant*.
- *Biomass co-firing* is a viable option for CO2 reduction which can be implemented immediately. More assessments are needed because biomass is affected by site-specific considerations, but there are no technological barriers and it depends only on site-specific economics.
- *Should India seek to develop IGCC projects with imported coal?* IGCC has the potential to increase plant efficiency and could be the least cost option if CCS is required in the future. IGCC using imported coal is commercially available and requires no substantial technological

development. However, IGCC costs are higher than supercritical pulverized coal plants making it difficult to finance such projects. IGCC costs are also expected to decline over time, as more plants are built and operated. So, the decision to implement IGCC with imported coal relates to the country's strategy to participate in the advancement of this technology and be better prepared in case CCS is required.

- *In parallel, India may elect to develop and demonstrate fluidized bed IGCC technology,* which is the only gasification option suitable for Indian coal. This technology, especially the oxygen-blown version, which is more suitable for CCS, is still in early stages of development and requires further demonstration at approximately 100 MW size.
- *Carbon capture and sequestration is being considered worldwide as a key option for climate change response.* While India does not have to commit to this option, it should consider assessing its sequestration potential and monitor CCS-related developments. CCS would have also an impact on the various technologies and may change their cost-effectiveness (relative to each other). For example, preliminary assessments carried out by various organizations have concluded that IGCC seems to be more cost-effective than pulverized coal. However, there is a great deal of uncertainty associated with these assessments, as many CCS-related issues are outstanding. If CCS is required, the key coal-fired options are:
    - High efficiency (USC) pulverized coal plants with CCS;
    - IGCC with CCS; and
    - Oxy-fuel with CCS.

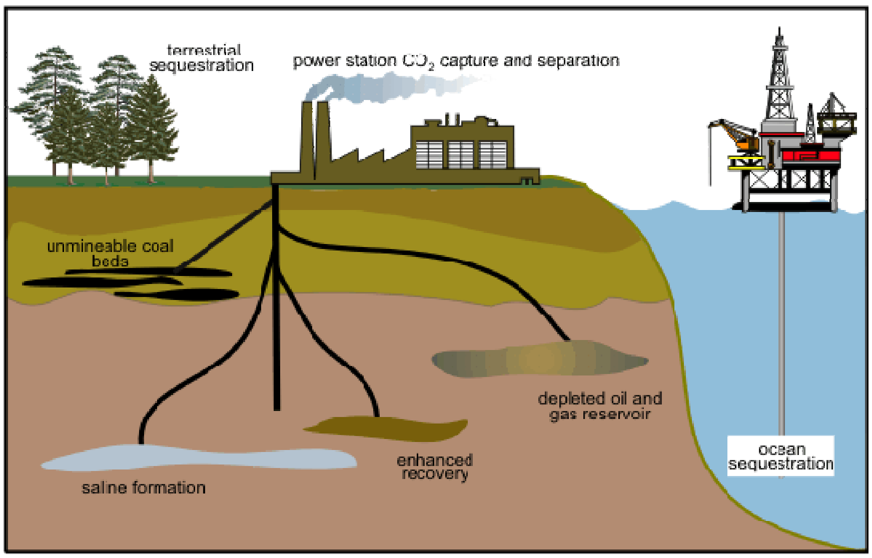
Presently, there is no clear winner among these three options, and the industry is pursuing all of them.   Whether India decides to be involved in such technological developments or not relates to its overall climate change strategy.

Appendix 1: Carbon Capture and Sequestration

Carbon capture and storage (CCS) involves capturing carbon dioxide from the flue gas of fossil power plants and long-term sequestration/storage. CCS has been identified by the IPCC as one of the key technologies in global efforts to stabilize CO_2 concentrations at 450 or 550 ppm. Widespread adoption of CCS has the potential of reducing fossil fuel emissions by 85 percent or more by 2050.

Technology Basics: CCS involves three basic steps of CO_2 capture, transport and storage. CO_2 can be stored in formations like depleted oil and gas fields[28], saline aquifers, deep coal seams and oceans. Figure 1.1 shows the various options for sequestration.

Figure 1.1: Sequestration Options Underground and in the Ocean



First, carbon dioxide is extracted from the waste stream of the fossil fuel plant using chemical or physical processes. The main options available are:

- *Pre-combustion* involving mainly IGCC technology; sorbents such as Selexol and Rectisol are used for such separation.
- *Oxy-combustion,* which involves combustion using oxygen instead of air; and
- *Post-combustion* which employs chemical and physical methods to separate CO_2 from the flue gas stream. The flue gas is passed through a sorbent mixture containing chemical substances like hindered amines or through membranes. Chemical absorption provides the most selective process of separation and hence is most favored for this kind of separation. After separation of CO_2 from the rest

[28] CCS can also be done in oceans but this is not yet practically proven beyond computer simulations. Its related environmental impacts have not been simulated yet and most scientists do not expect it to happen in the next 20 years and hence it is not discussed in this paper.

of the flue gases, the CO_2 is extracted using a chemical process. The sorbents are recycled after extraction of CO_2.

For post-combustion capture, the most common option, involves chemical absorption with monoethanolamine (MEA). However, there are other post- combustion processes which are in the early stage of their development (laboratory or pilot scale) and may change the competitiveness of the power generation technologies. For example, Alstom's *chilled ammonia* process promises to have much lower auxiliary power requirements and better economics than MEA; this technology is being tested at We Energies' Pleasant Prairie plant (5 MW scale) and AEP's Mountaineer station (30 MW scale).

After the CO_2 has been captured, it is then concentrated and transported to the site of its storage. Transport of CO_2 through pipelines is common and does not face any issues other than project-specific economics. Presently there are approximately 3,500 miles of CO_2 pipelines in the United States. These pipelines are similar to natural gas pipelines and there is no technological innovation needed to transfer large amounts of CO_2.

Underground storage of CO_2 at depths of roughly 1 km is likely to hold it for many years. CCS in depleted oil and gas fields to allow further extraction has been practiced for the past few decades in various regions across the world. CO_2 in deep coal mine beds allows for economical extraction of coal bed methane. Carbon storage is done typically at depths ranging from 800 to 3000m, depending on local geology, exploration history and settlement situation. The most important consideration is to have a layer or more of cap-rock that keeps the carbon deeply buried. The first step to successful storage is suitable site selection.

Sequestration deep in the ocean is practically feasible as liquid CO_2 is heavier than seawater and it is expected to be trapped for decades and even centuries. However, the CO_2 could increase the ocean's acidity and have adverse (and presently unknown) consequences on marine life. For this reason, ocean sequestration faces serious issues and is not considered viable at least for the time being.

Hence, the most common sequestration options being explored are geological sequestration in coal beds, active and depleted oil/gas fields, deep aquifers and miner cavers/salt domes. Depleted oil/gas fields are the most promising near-term option and do not face serious issues. However, available active and depleted oil/gas fields in the United States have adequate capacity for less then 2 years of CO_2 production from the power sector.

Deep saline aquifers seem to be the best long-term solution with an estimated of 5-500 billion tons of CO_2 capacity; such aquifers are widely dispersed in the United States and it is estimated that approximately 65 percent of the CO_2 produced could be injected directly without the need for major pipelines. However, there is substantial technical and cost uncertainty associated with this option. Also, there is significant uncertainty associated with coal beds. Mine caverns/salt domes have high storage potential but the associated costs are very high.

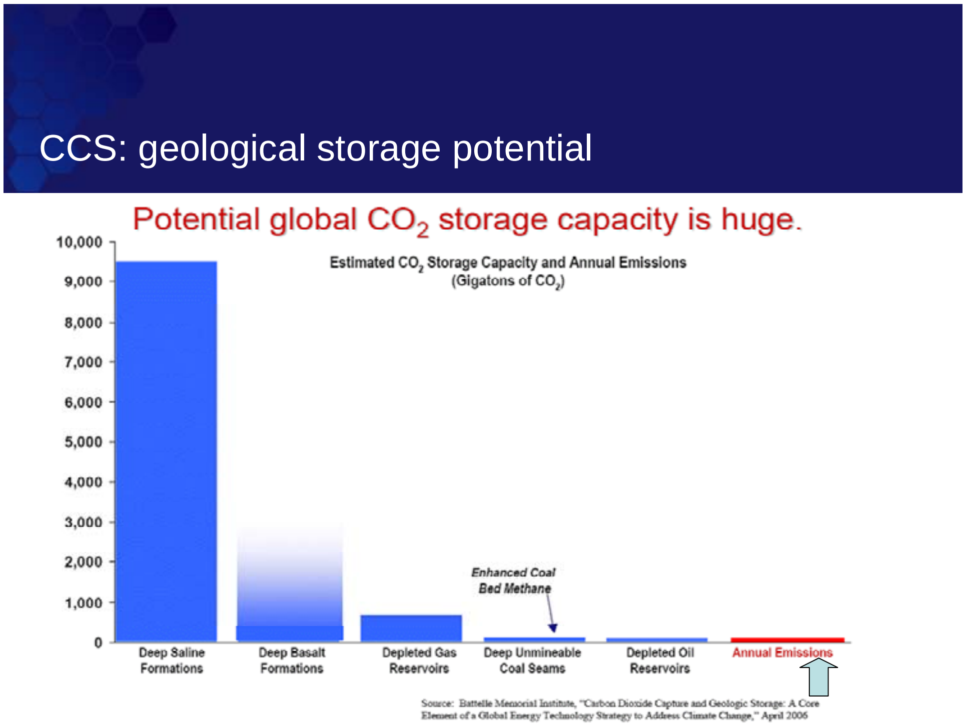
More detailed information on CCS is provided in Chapter 4 of the MIT report (http://web.mit.edu/coal/).

Is there Enough Storage Capacity?

Key questions related to CCS include: *Is there enough storage capacity worldwide? Is there enough storage capacity within reasonable distance from the power plant to make transport and sequestration feasible and practical?*

The conclusion of recent studies is that there is more than adequate storage space for sequestration worldwide (see Figure 1.2).   However, not all the countries are blessed with the "right geology". The United States and parts of China have the good geological formations for sequestration. Other countries, such as Japan, do not have such geological formations. In the case of India, there is not enough information available.

Figure 1.2: Storage Space for Sequestration



Economics of Power Generation Technologies with CCS

As mentioned earlier in this report, if CCS is not needed, IGCC capital costs are usually 15-20 percent higher than pulverized coal plants burning bituminous coal and located near sea level plant sites. For high elevation (e.g., in Wyoming) and subbituminous coal or lignites, the capital cost gap increases further in favor of pulverized coal.

When CCS is required, ***most comparisons show that IGCC is more competitive than pulverized coal***. The following table shows the capital costs from two recent studies:

- The most recently published costs for IGCC and competing technologies has been published by DOE in May 2007: http://www.netl.doe.gov/energy-analyses/pubs/Bituminous%20Baseline_Final%20Report.pdf.
- MIT published a comprehensive report on coal options, including IGCC and Carbon Capture & Sequestration (CCS) in early 2007: http://web.mit.edu/coal/

	Size (MW)	Supercritical ($/kW)	IGCC ($/kW)	SC higher than IGCC (%)
DOE (2007)	700	2838	2496	12.07
MIT (2007)	500	2140	1890	11.68

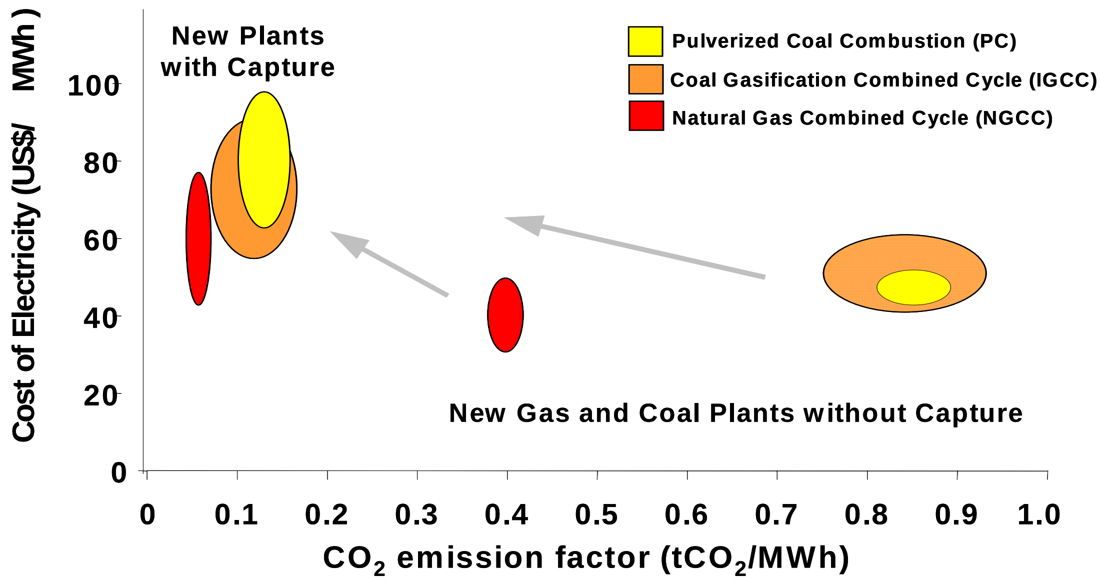
Another study by the International Energy Agency/Coal Research (IEA/CR)[29] estimates the following production costs:

- GE/IGCC with CCS: 6.94 cents/kWh
- Shell/IGCC with CCS: 7.68 cents/kWh
- Pulverized coal with CCS: 7. 40-7.76 cents/kWh

However, the advantage is not significant and if the outstanding issues associated with CCS (and IGCC) are considered (see below), ***it is very difficult to reach a clear conclusion in favor of the one or the other technology***. In general, all these estimates are within the range of uncertainty considering that a number of issues still remain associated with both IGCC and CCS (for CCS see below); also, site-specific considerations may change the conclusion. For example, the distance between the power plant and the sequestration site or the type of geological formation and the required depth for sequestration could affect significantly the outcome. The fact that the PC+CCS and IGCC+CCS are practically overlapping is shown in Figure 1.3 from the IPCC Special Report on CCS (2005).

[29] *J. Davison, Energy 32 (2007) 1163-1176*

Figure 1.3: Power Generation and Carbon Mitigation Costs of CCS



Some of these concerns associated with IGCC and CCS are brought up in the recent report published by MIT (http://web.mit.edu/coal/), which concludes that:

- CCS is the enabling technology (for IGCC).
- Several large scale CCS projects are needed to demonstrate the technical, economic and environmental performance of CCS; these projects are needed urgently and require significant US government support.
- While today IGCC appears to be the economic choice when CCS is included, the demonstrations could change the winner; so, it is recommended that the US government should not pick a winning technology for carbon capture, but make sure that all reasonable options are demonstrated.
- Given the technical uncertainty and the current absence of a carbon charge, there is no economic incentive for private firms to undertake CCS projects.

Outstanding issues associated with CCS

The MIT report highlighted the importance and urgent need for demonstrating alternative CCS options in large scale. These demonstration projects need to address issues such as:

- Technical Issues:
  - The largest MEA plant in operation today is adequate to handle CO_2 from a 50 MW power plant. So, scale up of the technology has some uncertainties both technical and economic.
  - Efficiency improvements need to be made in the compression of CO_2.
  - Is there assurance that the sequestered CO_2 will not leak into the environment after some years? This is particularly important in areas with

high seismic activity. In general, scientists and engineers are not in a position to certify that no leaks will occur.
   - How can such leakage be monitored?
   - What if CO_2 leaks into the groundwater supplies?
   - On-going pilot projects are addressing some of the issues but not as an integrated system; large scale demonstrations are needed.

- Economic Issues: In general, preliminary economics are just rough estimates and are not adequate for project planning purposes. More detail assessments are needed to improve the equipment design and accuracy of the cost estimates. This is particularly important for deep saline aquifers, the most viable sequestration option.

- Legal Issues:
   - Who has the property rights to underground space for such long term storage? All studies assume that there is no need to pay anybody, but this has no legal basis; it could be challenged in court.
   - There are legal considerations for the potential CO_2 leak into the groundwater supplies. "Legal Shield" would be needed. EPA needs to issue regulations.
   - If significant amounts of CO_2 leak in a short period of time there is a possibility of asphyxiation of people and animals.

- Regulatory issues:
   - There is no institutional framework to govern geological sequestration of CO_2 at large scale for a very long period of time. Building a regulatory framework for CCS is a high priority item.
   - Should CCS be required by both existing and new power plans?
   - Should existing power plants (at least the relatively new ones) be grandfathered?

CCS-ready

Until most of the above issues are clarified, it is nearly impossible for any organization to commit such huge investments in CCS and IGCC technologies. However, there is increasing pressure on power companies, especially in Europe and the United States, to build new power plants which are "CCS-ready". "CCS-ready" refers to design provisions which are included to help a plant add CO_2 capture after it has commenced operation. Although capture ready features increase the initial cost of the plant, they have the potential for significant savings when CCS is implemented.

Capture ready options for IGCC include:

- Over-sizing of the gasifier and air separation unit to ensure sufficient hydrogen production to maintain full load of the gas turbine.
- Higher gasification pressure to reduce CO_2 compression requirements and increase syngas throughput.

- Use of water-quench gas cooler to fit better the chemistry of shift reaction and avoid the cost of other types of cooler which would need to be eliminated after the capture retrofit.
- Provision for supplemental duct firing to increase HRSG steam production to help offset the output loss of the combined cycle steam turbine output.

An EPRI study in 2003 estimates that the above increase the cost of IGCC by approximately 5 percent. However, this investment will reduce the CO_2 capture retrofit costs and most importantly it will allow for higher output resulting in an overall 5 percent reduction in power production cost (comparing the cases of retrofitting IGCCs without capture ready and with capture ready designs).

"Capture-ready" pulverized coal plant requires:

- Design of the steam cycle to better accommodate CO_2 compression inter-cooling
- Increased FGD size assuming that MonoEthanolAmine (MEA) is used for CO_2 capture
- Other design features depend on the type of CO_2 capture technology used.

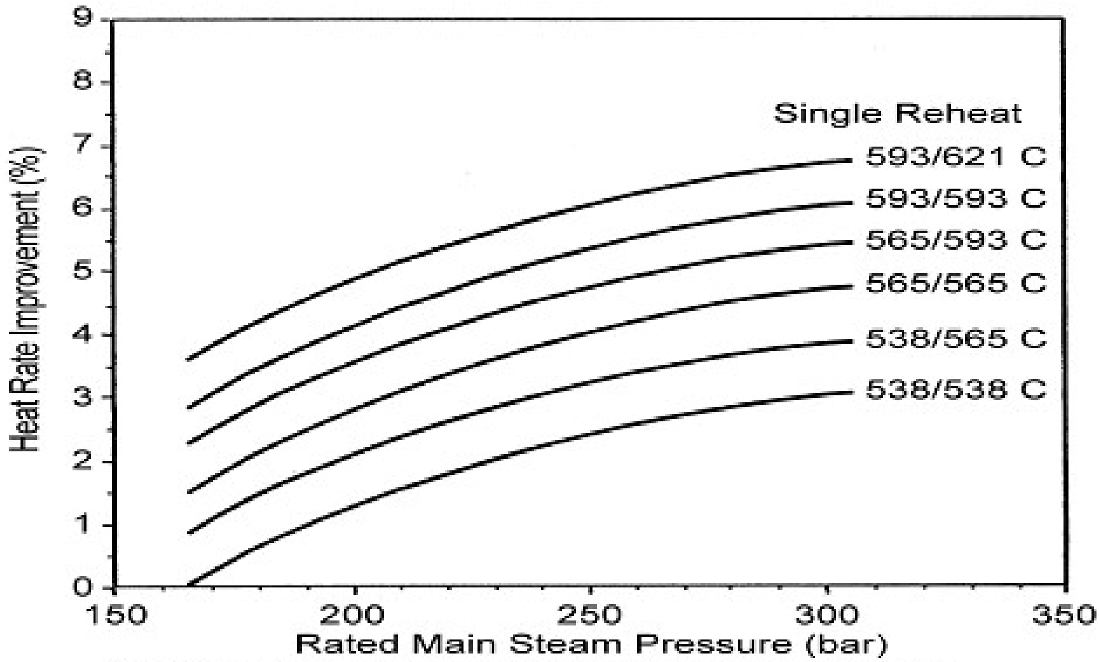
The same EPRI study estimates that CO_2 capture increases the capital costs of an IGCC plant by approximately 13 percent while the pulverized coal plant by 25 percent.

In summary, CCS is feasible through various mechanisms including:

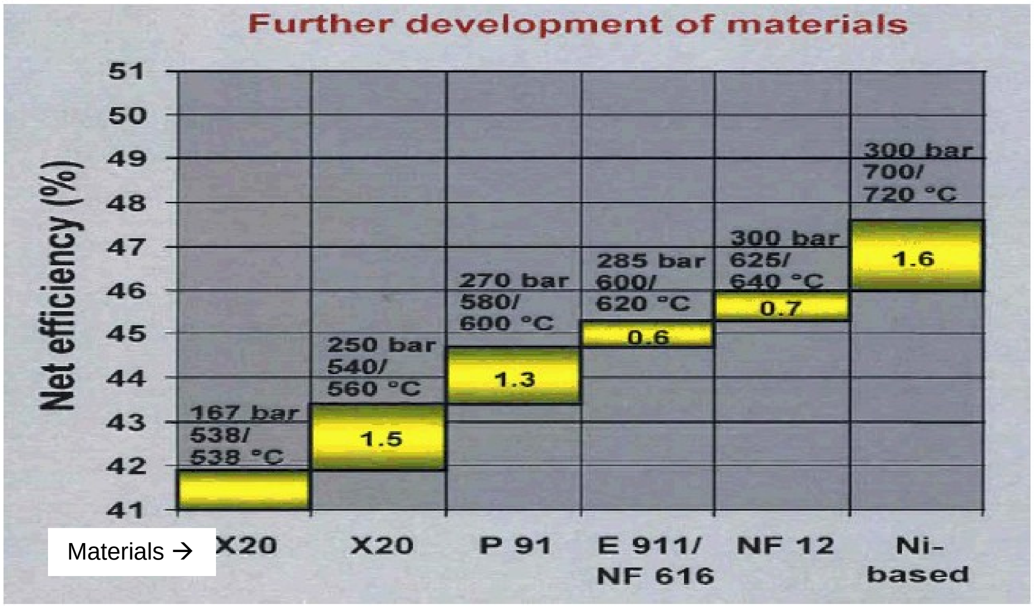
- IGCC + CO_2 capture;
- Oxy-combustion + CO_2 capture; and
- Pulverized coal + CO_2 capture.

Presently there is not enough information to determine which of these options is more competitive.

Appendix 2: Relationship Between Steam Conditions and Efficiency



Figures on curve are main and reheat steam temperatures (C)



, Impact of steam parameters and materials on the plant overall efficiency

Bibliography

Armor, A.F and Oliker, I, "Boiler design for low rank coal in the Former USSR", EPRI, 2002

CEA, "Report of the Committee to recommend next higher size of coal-fired thermal power stations", November, 2003

Electric Power Development Corp of Japan, " Adoption of supercritical technology for Sipat super thermal power plant", January 1999

IEA/Clean Coal Center, Profiles: "Developments in Fluidized Bed Combustion Technology", June 2006, PF 06-03

Mao, Jianxiong, "Electrical Power Sector and Supercritical Units in China" presented at the Workshop on Design of Efficient Coal Power Plants, Vietnam, October 15-16, 2007

Marion, J., Bozzuto, C., Nsakala, N., Liljedahl, G., "Evaluation of Advanced Coal Combustion & Gasification Power Plants with Greenhouse Gas Emission Control", Topical Phase-I, DOE-NETL Report under Cooperative Agreement No. DE-FC26-01NT41146 Prepared by Alstom Power Inc., May 15, 2003

MIT, "The future of coal", March 2007 (http://web.mit.edu/coal/)

Paelinck, Philippe, "Addressing clean power and CO2", Alstom, Presentation at World Bank, Aug 29, 2007

Palkes, M., Waryasz, R., "Economics and Feasibility of Rankine Cycle Improvements for Coal Fired Power Plants", Final DOE-NETL Report under Cooperative Agreement No. DE-FCP-01NT41222 Prepared by Alstom Power Inc., February, 2004

US DOE Baseline Study on for Fossil Energy Plants, 2007

US National Renewable Energy Laboratory, "Biomass cofiring: A renewable alternative for utilities", DOE/GO-1020000-1055, June 2000

World, Bank, "Financing Clean Coal Technologies in China", October 2001

World, Bank, "Policy Recommendations to SDPC Supporting the Deployment of Clean Coal Technologies in China", March 2001

World Bank, "Technical and Economic Assessment of Grid, Mini-Grid and Off-Grade Electrification Technologies", September, 2006

World Energy Council, "Performance of Generating Plant 2004", 2005