Chapter 1 – Purpose of the Study

The risk of adverse climate change from global warming forced in part by growing greenhouse gas emissions is serious. While projections vary, there is now wide acceptance among the scientific community that global warming is occurring, that the human contribution is important, and that the effects may impose significant costs on the world economy. As a result, governments are likely to adopt carbon mitigation policies that will restrict CO_2 emissions; many developed countries have taken the first steps in this direction. For such carbon control policies to work efficiently, national economies will need to have many options available for reducing greenhouse gas emissions. As our earlier study — *The Future of Nuclear Power* — concluded, the solution lies not in a single technology but in more effective use of existing fuels and technologies, as well as wider adoption of alternative energy sources. This study —*The Future of Coal* — addresses one option, the continuing use of coal with reduced CO_2 emissions.

Coal is an especially crucial fuel in this uncertain world of future constraint on CO_2 emissions. Because coal is abundant and relatively cheap — \$1–2 per million Btu, compared to \$ 6–12 per million Btu for natural gas and oil — today, coal is often the fuel of choice for electricity generation and perhaps for extensive synthetic liquids production in the future in many parts of the world. Its low cost and wide availability make it especially attractive in major developing economies for meeting their pressing energy needs. On the other hand, coal faces significant environmental challenges in mining, air pollution (including both criteria pollutants and mercury), and importantly from the perspective of this study, emission of carbon dioxide (CO_2). Indeed coal is the largest contributor to global CO_2 emissions from energy use (41%), and its share is projected to increase.

This study examines the factors that will affect the use of coal in a world where significant constraints are placed on emissions of CO_2 and other greenhouse gases. We explore how the use of coal might adjust within the overall context of changes in the demand for and supply of different fuels that occur when energy markets respond to policies that impose a significant constraint on CO_2 emissions. Our purpose is to describe the technology options that are currently and potentially available for coal use in the generation of electricity if carbon constraints are adopted. In particular, we focus on **carbon capture and sequestration** (CCS) — the separation of the CO_2 combustion product that is produced in conjunction with the generation of electricity from coal and the transportation of the separated CO_2 to a site where the CO_2 is sequestered from the atmosphere. Carbon capture and sequestration add significant complexity and cost to coal conversion processes and, if deployed at large scale, will require considerable modification to current patterns of coal use.

We also describe the research, development, and demonstration (RD&D) that should be underway today, if these technology options are to be available for rapid deployment in the future, should the United States and other countries adopt carbon constraint policies. Our recommendations are restricted to what needs to be done to establish these technology options to create viable choices for future coal use.

Our study does not address climate policy, nor does it evaluate or advocate any particular set of carbon mitigation policies. Many qualified groups have offered proposals and analysis about what policy measures might be adopted. We choose to focus on what is needed to create technology options with predictable performance and cost characteristics, if such policies are adopted. If technology preparation is not done today, policy-makers in the future will be faced with fewer and more difficult choices in responding to climate change.

We are also realistic about the process of adoption of technologies around the world. This is a global problem, and the ability to embrace a new technology pathway will be driven by the industrial structure and politics in the developed and developing worlds. In this regard, we offer assessments of technology adoption in China and India and of public recognition and concern about this problem in the United States.

The overarching goal of this series of MIT energy studies is to identify different combinations of policy measures and technical innovations that will reduce global emissions of CO_2 and other greenhouse gases by mid-century. The present study on *The future of coal* and the previous study on *The future of nuclear power* discuss two of the most important possibilities.

An outline of this study follows:

Chapter 2 presents a framework for examining the range of global coal use in all energy-using sectors out to 2050 under alternative economic assumptions. These projections are based on the MIT Emissions Predictions and Policy Analysis (EPPA) model. The results sharpen understanding of how a system of global markets for energy, intermediate inputs, and final goods and services would respond to imposition of a carbon charge (which could take the form of a carbon emissions tax, a cap and trade program, or other constraints that place a de facto price on carbon emissions) through reduced energy use, improvements in energy efficiency, switching to lower CO_2-emitting fuels or carbon-free energy sources, and the introduction of CCS.

Chapter 3 is devoted to examining the technical and likely economic performance of alternative technologies for generating electricity with coal with and without carbon capture and sequestration in both new plant and retrofit applications. We analyze air and oxygen driven pulverized coal, fluidized bed, and IGCC technologies for electricity production. Our estimates for the technical and environmental performance and for likely production cost are based on today's experience.

Chapter 4 presents a comprehensive review of what is needed to establish CO_2 sequestration as a reliable option. Particular emphasis is placed on the need for geological surveys, which will map the location and capacity of possible deep saline aquifers for CO_2 injection in the United States and around the world, and for demonstrations at scale, which will help establish the regulatory framework for selecting sites, for measurement, monitoring and verification systems, and for long-term stewardship of the sequestered CO_2. These regulatory aspects will be important factors in gaining public acceptance for geological CO_2 storage.

Chapter 5 reports on the outlook for coal production and utilization in China and India. Most of our effort was devoted to China. China's coal output is double that of the United States, and its use of coal is rapidly growing, especially in the electric power sector. Our analysis of the Chinese power sector examines the roles of central, provincial, and local actors in investment and operational decisions affecting the use of coal and its environmental impacts. It points to a set of practical constraints on the ability of the central government to implement restrictions on CO_2 emissions in the relatively near-term.

Chapter 6 evaluates the current DOE RD&D program as it relates to the key issues discussed in Chapters 2, 3, and 4. It also makes recommendations with respect to the content and organization of federally funded RD&D that would provide greater assurance that CC&S would be available when needed.

Chapter 7 reports the results of polling that we have conducted over the years concerning public attitudes towards energy, global warming and carbon taxes. There is evidence that public attitudes are shifting and that support for policies that would constrain CO_2 emissions is increasing.

Chapter 8 summarizes the findings and presents the conclusions of our study and offers recommendations for making coal use with significantly reduced CO_2 emissions a realistic option in a carbon constrained world.

The reader will find technical primers and additional background information in the appendices to the report.

Chapter 2 — The Role of Coal in Energy Growth and CO_2 Emissions

INTRODUCTION

There are five broad options for reducing carbon emissions from the combustion of fossil fuels, which is the major contributor to the anthropogenic greenhouse effect:

- Improvements in the efficiency of energy use, importantly including transportation, and electricity generation;
- Increased use of renewable energy such as wind, solar and biomass;
- Expanded electricity production from nuclear energy;
- Switching to less carbon-intensive fossil fuels; and
- Continued combustion of fossil fuels, especially coal, combined with CO_2 capture and storage (CCS).

As stressed in an earlier MIT study of the nuclear option,[1] if additional CO_2 policies are adopted, it is not likely that any one path to emissions reduction will emerge. All will play a role in proportions that are impossible to predict today. This study focuses on coal and on measures that can be taken now to facilitate the use of this valuable fuel in a carbon-constrained world. The purpose of this chapter is to provide an overview of the possible CO_2 emissions from coal burning over the next 45 years and to set a context for assessing policies that will contribute to the technology advance that will be needed if carbon emissions from coal combustion are to be reduced.

Coal is certain to play a major role in the world's energy future for two reasons. First, it is the lowest-cost fossil source for base-load electricity generation, even taking account of the fact that the capital cost of a supercritical pulverized coal combustion plant (SCPC) is about twice that of a natural gas combined cycle (NGCC) unit. And second, in contrast to oil and natural gas, coal resources are widely distributed around the world. As shown in Figure 2.1, drawn from U.S. DOE statistics,[2] coal reserves are spread between developed and developing countries.

The major disadvantages of coal come from the adverse environmental effects that accompany its mining, transport and combustion. Coal combustion results in greater CO_2 emissions than oil and natural gas per unit of heat output because of its relatively higher ratio of carbon to hydrogen and because the efficiency (i.e., heat rate) of a NGCC plant is higher than that of a SCPC plant. In addition to CO_2, the combustion-related emissions of coal generation include the criteria pollutants: sulfur dioxide (SO_2), nitrogen oxides (NO and NO_2,

Figure 2.1 Recoverable Coal Reserves

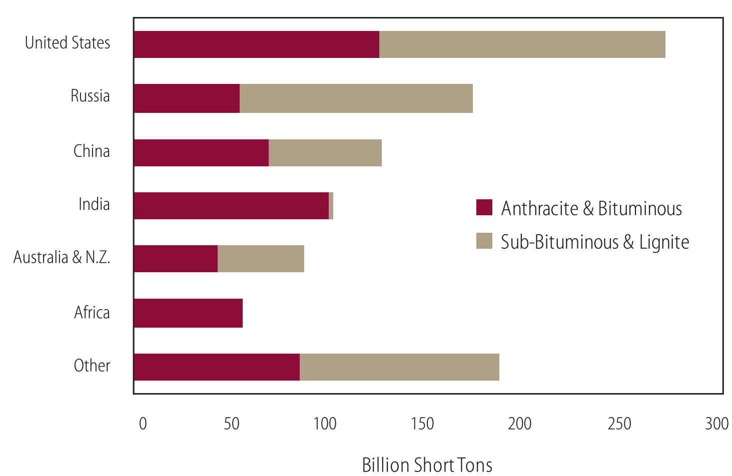


Table 2.1 2004 Characteristics of World Coals

	PRODUCTION (Million Short Tons)	AVERAGE HEAT CONTENT (Thousand Btu/Short Ton)
US	1,110	20,400
Australia	391	20,300
Russia	309	19.000
South Africa	268	21,300
India	444	16,400
China	2,156	19,900

Source: DOE/EIA IEA (2006), Tables 2.5 and C.6

Table 2.2 Coal Use Projections and Average Rate of Increase 2002–2030

	2003	2010	2015	2020	2025	2030	AV. % INCREASE
US							
Total *(Quadrillion Btu)*	22.4	25.1	25.7	27.6	30.9	34.5	1.6
% Electric	90	91	91	91	91	89	1.6
China							
Total *(Quadrillion Btu)*	29.5	48.8	56.6	67.9	77.8	89.4	4.2
% Electric	55	55	57	55	56	56	4.2

Source: EIA/EIA IEO (2006), Tables D1 and D9.

jointly referred to as NOx), particulates, and mercury (Hg). Also, there are other aspects of coal and its use not addressed in this study. For example,

Coal is not a single material. Coal composition, structure, and properties differ considerably among mining locations. Table 2.1, also drawn from DOE data,[3] shows the wide variation of energy content in the coals produced in different countries. These differences are a consequence of variation in chemical composition —notably water and ash content —which has an important influence on the selection of coal combustion technology and equipment. This point is discussed further in Chapter 3.

Coal mining involves considerable environmental costs. The environmental effects of mining include water pollution and land disturbance as well as the release of another greenhouse gas, methane (CH_4), which is entrained in the coal. Also, mining involves significant risk to the health and safety of miners.

Patterns of coal use differ among countries. In mature economies, such as the United States, coal is used almost exclusively to generate electricity. In emerging economies, a significant portion of coal used is for industrial and commercial purposes as illustrated in Table 2.2 comparing coal use in the United States and China.[4]

We begin this exploration of possible futures for coal with a brief overview of its current use and associated CO_2 emissions, and projections to 2030, assuming there are no additional policies to restrict greenhouse gas emissions beyond those in place in 2007. For these business-as-usual projections we use the work of the U.S. Department of Energy's Energy Information Administration (EIA). We then turn to longer-term projections and consider the consequences for energy markets and coal use of alternative policies that place a penalty on carbon emissions. For this latter part of the assessment, we apply an economic model developed at MIT, to be described below. This model shows that, among other effects of such polices, a carbon charge[5] of sufficient magnitude will favor higher-efficiency coal-burning technologies and the application of carbon capture and sequestration (CSS), contributing to a reduction of emissions from coal and sustaining its use in the face of restrictions on CO_2. In the longer-term projections, we focus on the U.S. and world totals, but we also include results for China to emphasize the role of large developing countries in the global outlook.

THE OUTLOOK FOR COAL ABSENT ADDITIONAL CLIMATE POLICY

Each year in its *International Energy Outlook,* the DOE/EIA reviews selected energy trends. Table 2.3 summarizes the EIA's Reference Case projection of primary energy use (i.e., fossil fuels, hydro, nuclear, biomass, geothermal, wind and solar) and figures for coal consumption alone. The projections are based on carbon emission regulations currently in effect. That is, developed countries that have ratified the Kyoto Protocol reduce their emissions to agreed levels through 2012, while developing economies and richer countries that have not agreed to comply with Kyoto (the United States and Australia) do not constrain their emissions growth. The report covers the period 1990 to 2030, and data are presented for countries grouped into two categories:

- OECD members, a richer group of nations including North America (U.S., Canada and Mexico), the EU, and OECD Asia (Japan, Korea, Australia and New Zealand).
- Non-OECD nations, a group of transition and emerging economies which includes Russia and other Non-OECD Europe and Eurasia, Non-OECD Asia (China, India and others), the Middle East, Africa, and Central and South America.

It can be seen that the non-OECD economies, though consuming far less energy than OECD members in 1990, are projected to surpass them within the next five to ten years. An even more dramatic picture holds for coal consumption. The non-OECD economies consumed about the same amount as the richer group in 1990, but are projected to consume twice as much by 2030. As would be expected, a similar picture holds for CO_2 emissions, as shown in Table 2.4. The non-OECD economies emitted less CO_2 than the mature ones up to the turn of the century, but because of their heavier dependence on coal, their emissions are expected to surpass those of the more developed group by 2010. The picture for emissions from coal burning, also shown in the table, is even more dramatic.

Table 2.3 World Consumption of Primary Energy and Coal 1990–2030

	TOTAL PRIMARY ENERGY (QUADRILLION Btu)			TOTAL COAL (MILLION SHORT TONS)		
	OECD (U.S.)	NON-OECD	TOTAL	OECD (U.S.)	NON-OECD	TOTAL
1990	197 (85)	150	347	2,550 (904)	2,720	5,270
2003	234 (98)	186	421	2,480 (1,100)	2,960	5,440
2010	256 (108)	254	510	2,680 (1,230)	4,280	6,960
2015	270 (114)	294	563	2,770 (1,280)	5,020	7,790
2020	282 (120)	332	613	2,940 (1,390)	5,700	8,640
2025	295 (127)	371	665	3,180 (1,590)	6,380	9,560
2030	309 (134)	413	722	3440 (1,780)	7,120	10,560

Source: DOE/EIA IEO (2006): Tables A1 & A6

Table 2.4 CO_2 Emissions by Region 1990–2030

	TOTAL EMISSIONS (BILLION METRIC TONS CO_2)			EMISSIONS FROM COAL (BILLION METRIC TONS CO_2)			COAL % OF TOTAL
	OECD (U.S.)	NON-OECD	TOTAL	OECD (U.S.)	NON-OECD	TOTAL	
1990	11.4 (4.98)	9.84	21.2	4.02 (1.77)	4.24	8.26	39
2003	13.1 (5.80)	11.9	25.0	4.25 (2.10)	5.05	9.30	37
2010	14.2 (6.37)	16.1	30.3	4.63 (2.35)	7.30	11.9	39
2015	15.0 (6.72)	18.6	33.6	4.78 (2.40)	8.58	13.4	40
2020	15.7 (7.12)	21.0	36.7	5.06 (2.59)	9.76	14.8	40
2025	16.5 (7.59)	23.5	40.0	5.42 (2.89)	10.9	16.3	41
2030	17.5 (8.12)	26.2	43.7	5.87 (3.23)	12.2	18.1	41

Source: DOE/EIA IEO (2006): Tables A10 & A13

The qualitative conclusions to be drawn from these reference case EIA projections are summarized in Table 2.5, which shows the growth rates for energy and emissions for the period 2003–30. Worldwide energy consumption grows at about a 2% annual rate, with emerging economies increasing at a rate about three times that of OECD group. Emissions of CO_2 follow a similar pattern. Coal's contribution to total CO_2 emissions had declined to about 37% early in the century, and (as can be seen in Table 2.4) this fraction is projected to grow to over 40% by to 2030. Clearly any policy designed to constrain substantially the total CO_2 contribution to the atmosphere cannot succeed unless it somehow reduces the contribution from this source.

Table 2.5 Average Annual Percentage Growth 2002–2030

	OECD	US	NON-OECD	CHINA	INDIA	TOTAL
Energy	1.0	1.2	3.0	4.2	3.2	2.0
Coal	1.2	1.8	3.3	4.2	2.7	2.5
Total CO_2	1.1	1.3	3.0	4.2	2.9	2.1
Coal CO_2	1.2	1.6	3.3	4.2	2.7	2.5

Source: DOE/IEA AEO 2006: Tables A1, A6, A10 & A13

THE OUTLOOK FOR COAL UNDER POSSIBLE CO_2 PENALTIES

The MIT EPPA Model and Case Assumptions

To see how CO_2 penalties might work, including their implications for coal use under various assumptions about competing energy sources, we explore their consequences for fuel and technology choice, energy prices, and CO_2 emissions. Researchers at MIT's Joint Program on the Science and Policy of Global Change have developed a model that can serve this purpose. Their Emissions Predictions and Policy Analysis (EPPA) model is a recursive-dynamic multi-regional computable general equilibrium (CGE) model of the world economy.[6] It distinguishes sixteen countries or regions, five non-energy sectors, fifteen energy sectors and specific technologies, and includes a representation of household consumption behavior. The model is solved on a five-year time step to 2100, the first calculated year being 2005. Elements of EPPA structure relevant to this application include its equilibrium structure, its characterization of production sectors, the handling of international trade, the structure of household consumption, and drivers of the dynamic evolution of the model including the characterization of advanced or alternative technologies, importantly including carbon capture and storage (CCS).

The virtue of models of this type is that they can be used to study how world energy markets, as well as markets for other intermediate inputs and for final goods and services, would adapt to a policy change such as the adoption of a carbon emission tax, the establishment of cap-and-trade systems, or implementation of various forms of direct regulation of emissions. For example, by increasing the consumer prices of fossil fuels, a carbon charge would have broad economic consequences. These include changes in consumer behavior and in the sectoral composition of production, switching among fuels, a shift to low-carbon energy resources, and investment in more efficient ways to get the needed services from a given input of primary energy. A model like EPPA gives a consistent picture of the future energy market that reflects these dynamics of supply and demand as well as the effects of international trade.

Naturally, in viewing the results of a model of this type, a number of its features and input assumptions should be kept in mind. These include, for example, assumptions about:

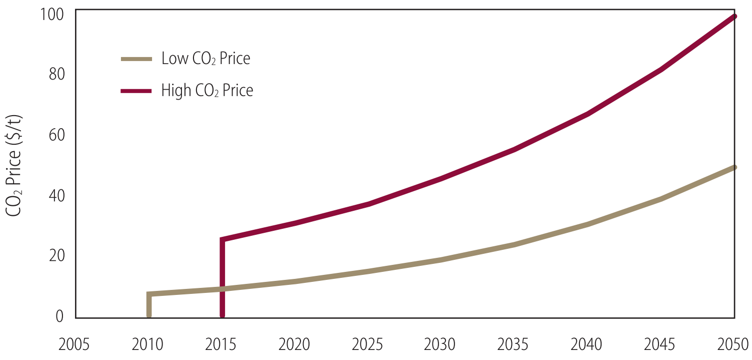
- Population and productivity growth that are built into the reference projection;
- The representation of the production structure of the economy and the ease of substitution between inputs to production, and the behavior of consumers in response to changing prices of goods and services;
- The cost and performance of various technology alternatives, importantly for this study including coal technologies (which have been calibrated to the estimates in Chapters 3 and 4 below) and competitor generation sources;
- The length of time to turn over the capital stock, which is represented by capital vintages in this model;
- The assumed handling of any revenues that might result from the use of a carbon tax, or from permit auctions under cap-and-trade systems.[7]

Thus our model calculations should be considered as illustrative, not precise predictions. The results of interest are not the absolute numbers in any particular case but the differences in outcomes for coal and CO_2 emissions among "what if" studies of different climate policy regimes and assumptions about competing energy types. In the assessment below we test the response of the energy sector and its CO_2 emissions to alternative assumptions about the penalty imposed on emissions in various parts of the world and about the effect of two uncertain influences on coal use: the pace of nuclear power development and the evolution of natural gas markets.

To explore the potential effects of carbon policy, three cases are formulated: a reference or *Business as Usual* (BAU) case with no emissions policy beyond the first Kyoto period,[8] and two cases involving the imposition of a common global price on CO_2 emissions. The two policy cases, a *Low* and a *High CO_2 price* path, are shown in Figure 2.2, with the CO_2 penalty stated in terms of 1997 $U.S. per ton of CO_2. This penalty or emissions price can be thought of as the result of a global cap-and-trade regime, a system of harmonized carbon taxes, or even a combination of price and regulatory measures that combine to impose the marginal penalties on emissions. The *Low CO_2 Price* profile corresponds to the proposal of the National Energy Commission[9], which we represent by applying its maximum or "safety valve" cap-and-trade price. It involves a penalty that begins in 2010 with $7 per ton CO_2 and increases at a real rate (e.g., without inflation) of 5% per year thereafter. The *High CO_2 Price* case assumes the imposition of a larger initial charge of $25 ton CO_2 in the year 2015 with a real rate of increase of 4% thereafter. One important question to be explored in the comparison of these two cases is the time when CSS technology may take a substantial role as an emissions reducing measure.

A second influence on the role of coal in future energy use is competition from nuclear generation. Here two cases are studied, shown in Table 2.6. In one, denoted as *Limited Nuclear*, it is assumed that nuclear generation, from its year 2000 level in the EPPA database of 1.95 million GWh, is held to 2.43 million GWh in 2050. At a capacity factor of 0.85, this corresponds to an expansion from a 1997 world installed total of about 261GW to some 327GW

Figure 2.2 Scenarios of Penalties on CO_2 Emissions
($/t CO_2 in constant dollars)



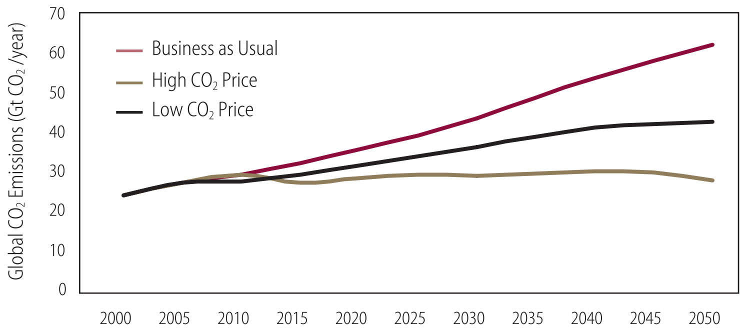
in 2050. The alternative case, denoted as *Expanded Nuclear* assumes that nuclear capacity grows to 1000GW over this period—a level identified as being feasible in the *MIT Future of Nuclear Power* study if certain conditions are met.[10]

The third influence on the role of coal studied here concerns the evolution of real natural gas prices over time. The EPPA model includes a sub-model of resources and depletion of fossil fuels including natural gas, and one scenario, denoted *EPPA-Ref Gas Price*, applies the model's own projection of gas prices (which differ by model regions) under the supply and demand conditions in the various simulations. In the Business-as-Usual (BAU) case with limited nuclear expansion, the real U.S. gas price

Table 2.6 Alternative Cases for Nuclear Generation
(Nuclear capacity in Million GWh/year)

		2050	
REGION	1997	LIMITED	EXPANDED
USA	0.57	0.58	2.23
Europe	0.76	0.94	1.24
Japan	0.28	0.42	0.48
Other OECD	0.07	0.10	0.34
FSU & EET	0.16	0.21	0.41
China	0.00	0.00	0.75
India	0.00	0.00	0.67
Other Asia	0.10	0.19	0.59
Rest of World	0.00	0.00	0.74
TOTAL	1.95	2.43	7.44

Figure 2.3 Global CO_2 Emissions under Alternative Policies with Universal, Simultaneous Participation, Limited Nuclear Expansion and EPPA-Ref Gas Prices *($GtCO_2$/year)*



is projected to rise by 2050 by a factor of 3.6 over the base year (1997) price of $2.33 per Mcf, which implies a price of around $8.40 per Mcf in 2050 in 1997 prices. To test the effect of substantial new discovery and development of low-cost LNG transport systems, a second *Low Gas Price* case is explored. In this case the EPPA gas transport sub-model is overridden by a low-cost global transport system which leads to lower prices in key heavy gas-consuming regions. For example, with the *Low Gas Price* scenario, the real 2050 price multiple for the U.S. is only 2.4 over the base year, or a price of $5.60/Mcf in 1997 prices.[11]

Results Assuming Universal, Simultaneous Participation in CO_2 Emission Penalties

In order to display the relationships that underlie the future evolution of coal use, we begin with a set of policy scenarios where all nations adopt, by one means or another, to the carbon emissions penalties as shown in Figure 2.2. Were such patterns of emissions penalties adopted, they would be sufficient to stabilize global CO_2 emissions in the period between now and 2050. This result is shown in Figure 2.3 on the assumption of *Limited Nuclear* generation, and *EPPA-Ref Gas Price*.

If there is no climate policy, emissions are projected to rise to over 60 $GtCO_2$ by 2050. Under the *High CO_2 Price* path, by contrast, global emissions are stabilized by around 2015 at level of about 28 $GtCO_2$. If only the *Low CO_2 Price* path is imposed, emissions would not stabilize until around 2045 and then at a level of approximately 42 $GtCO_2$ per year.[12]

Figure 2.4 shows how global primary energy consumption adjusts in the EPPA model solution for the *High CO_2 Price* case with *Limited Nuclear* expansion and *EPPA-Ref* gas prices. The increasing CO_2 price leads to a reduction in energy demand over the decades and to adjustments in the composition of supply. For example, non-biomass renewables (e.g., wind) and commercial biomass (here expressed in terms of liquid fuel) both increase substantially.[13] Most important for this discussion is the effect on coal use. When the carbon price increases in 2015, coal use is initially reduced. However, in 2025 coal with CCS begins to gain market share, growing steadily to 2050 (and beyond) and leading to a resurgence of global coal consumption.

A further global picture of coal use under these alternative CO_2 price assumptions, assuming *Limited Nuclear* capacity and *EPPA-Ref Gas Price*, is shown in Table 2.7. Under the *Low CO_2 Price* trajectory, coal's contribution to 2050 global emissions is lowered from 32 $GtCO_2$ per year, to around 15 $GtCO_2$ per year while total coal consumption falls to 45% of its no-policy level (though still 100% above 2000 coal use). The contribution of carbon capture and storage (CCS) is relatively small in this case, because at this price trajectory CCS technology does not become economic until around 2035 or 2040, leading to a small market penetration by 2050. The picture differs substantially under assumption of the *High CO_2 Price* pattern. The contribution of CO_2 emissions from coal in 2050 is projected to be one-third that under the lower price path, yet coal use falls by only another 20% (and still remains 61% above the 2000 level). The key factor contributing to this result in 2050 can be seen in the third line in the table which shows the percentage of coal consumed using CCS technology. With higher CO_2 price levels early in the simulation period, CCS has the time and economic incentive to take a larger market share.

The point to take from Table 2.7 is that CO_2 mitigation policies at the level tested here will limit the expected growth of coal and associated emissions, but not necessarily constrict the production of coal below today's level. Also, the long-term future for coal use, and the achievement in CO_2 emissions abatement, are sensitive to the development and public acceptance of CCS technology and the timely provision of incentives to its commercial application.

An assumption of expanded nuclear capacity to the levels shown in Table 2.6 changes the global picture of primary energy consumption and the proportion met by coal. This case is shown in Figure 2.5 which, like Figure 2.4, imposes the high CO_2 price trajectory and EPPA-Ref gas prices. The possibility of greater nuclear expansion supports a small increase in total primary energy under no-policy conditions but leaves the total energy essentially unchanged under the pressure of high CO_2 prices. The main adjustment is in the consumption of coal, which is reduced from 161 EJ to 120 EJ in 2050 through a substitution of nuclear generation for coal with and without CO_2 capture and storage.

Table 2.8 provides some individual country detail for these assumptions and shows the sensitivity of the EPPA results to assumptions about nuclear expansion and natural gas prices. The top rows of the table again present the global figures for coal use along with the figures for the U.S. and China.[14] China's coal consumption at 27 EJ is slightly above the 24 EJ in the United States in 2000, but without climate policy, China's coal consumption is projected to increase to a level some 52% greater than that of the United States in 2050. On the other hand, the CO_2 penalty yields a greater percentage reduction in China than in the U.S.. By 2050 the *High CO_2 Price* has reduced Chinese use by 56%, but United States consumption is reduced by only 31%. The main reason for the difference in response is the composition of coal consumption, and to a lesser extent in a difference in the thermal efficiency of the electric power sectors of the two countries.

Figure 2.4 Global Primary Energy Consumption under High CO_2 Prices *(Limited Nuclear Generation and EPPA-Ref Gas Prices)*

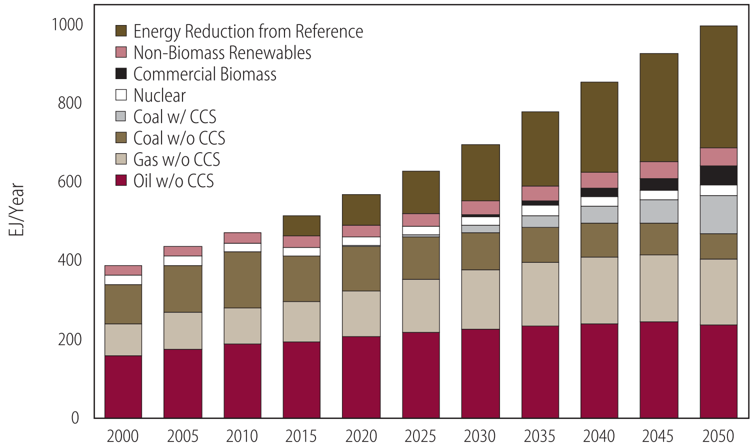
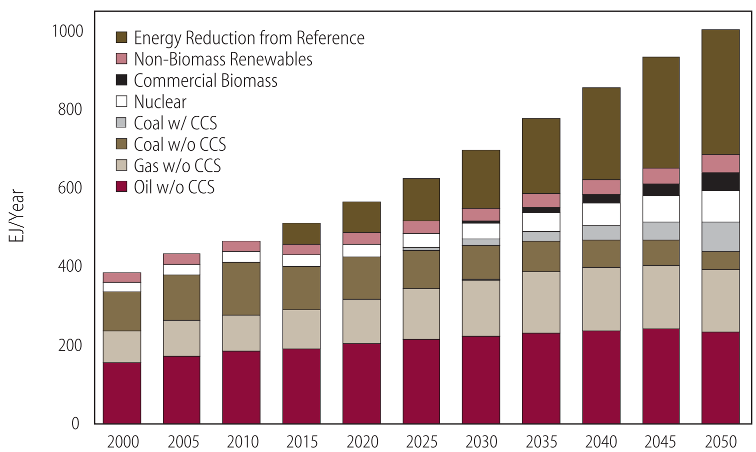


Table 2.7 Implications for Global Coal Consumption of Alternative CO_2 Price Assumptions

INDICATOR	BAU 2000	BAU 2050	LOW CO_2 PRICE 2050	HIGH CO_2 PRICE 2050
Coal CO_2 emissions ($GtCO_2$/yr)	9	32	15	5
Coal Consumption (EJ/yr)	100	448	200	161
% Coal with CCS	0	0	4	60

Assumes universal, simultaneous participation, limited nuclear expansion & EPPA-Ref gas price.

Figure 2.5 Global Primary Energy Consumption under High CO_2 Prices *(Expanded Nuclear Generation and EPPA-Ref Gas Prices)*



By 2050 in the reference scenario (*EPPA-Ref Gas Price* and *Limited Nuclear*), 54% of coal use in China is in non-electric power sectors compared with only 5% in the U.S.. Under the

Table 2.8 Coal Consumption

SCENARIO			BAU (EJ)		LOW CO_2 PRICE (EJ)	HIGH CO_2 PRICE (EJ)
GAS PRICE	NUCLEAR	REGION	2000	2050	2050	2050
EPPA-REF	LIMITED	GLOBAL	100	448	200	161
		US	24	58	42	40
		CHINA	27	88	37	39
EPPA-REF	EXPANDED	GLOBAL	99	405	159	121
		US	23	44	29	25
		CHINA	26	83	30	31
LOW	EXPANDED	GLOBAL	95	397	129	89
		US	23	41	14	17
		CHINA	26	80	13	31

Assumes universal, simultaneous participation.

High CO_2 Price policy, China's share of coal consumption in the other sectors declines to 12%, while the U.S. share of coal consumption outside of the electricity sector drops to 3%. Within the electric sector, U.S. power plants are relatively more thermally efficient than in China, so opportunities to lower coal consumption in China's power sector are greater.

Table 2.8 also displays the effect on coal use of alternative assumptions about the expansion of nuclear power. A growth of nuclear generating capacity at the level assumed in the *Expanded Nuclear* case directly displaces electricity from coal. For example, under *Business as Usual* the provision of expanded nuclear generation reduces 2050 global coal use from 448 to 405 EJ. This effect continues under the cases with penalties on CO_2 emissions. Moreover, if the influence of low gas prices is added to the greater nuclear penetration (a case shown in the bottom three rows) coal use declines further. Under these conditions, global coal use falls below 2000 levels under the *High CO_2 Price* case, and Chinese consumption would only reach its 2000 level in the years nearing 2050.

It can be seen in Figure 2.3 that in 2010 global CO_2 emissions are lower at the *Low* than at the *High CO_2 Price* scenario, whereas Table 2.7 indicates that by 2050 emissions are far lower at the stricter emissions penalty. This pattern is the result of the differential timing of the start of the mitigation policy and the influence of the two price paths on CCS, for which more detail is provided in Table 2.9. The lower CO_2 price path starts earlier and thus influences the early years, but under the high price path CCS enters earlier and, given the assumptions in the EPPA model about the lags in market penetration of such a new and capital-intensive technology, it has more time to gain market share. So, under *Limited Nuclear* growth and *EPPA-Ref Gas Price,* CCS-based generation under the *High CO_2 Price* reaches a global level ten times that under the *Low CO_2 Price*. An *Expanded Nuclear* sector reduces the total CCS installed in 2050 by about one-quarter.

The *Low Gas Price* assumption has only a small effect on CCS when the penalty on CO_2 emissions is also low, but it has a substantial effect under the *High CO_2 Price* scenario because the low gas prices delay the initial adoption of CCS. The gas price has a less pronounced effect after 2050.

Accompanying these developments are changes in the price of coal. The EPPA model treats coal as a commodity that is imperfectly substitutable among countries (due to transport costs and the imperfect substitutability among various coals), so that it has a somewhat different price from place to place. Table 2.10 presents these prices for the U.S. and China. Under the no-policy BAU (with *Limited Nuclear* and *EPPA-Ref Gas Price*), coal prices are projected to increase by 47% in the U.S. and by 60% in China.[15] Each of the changes explored—a charge on CO_2, expanded nuclear capacity or lower gas prices—would lower the demand for coal and thus its mine-mouth price. With high CO_2 prices, more nuclear and cheaper natural gas, coal prices are projected to be essentially the same in 2050 as they were in 2000.

Results Assuming Universal but Lagged Participation of Emerging Economies

The previous analysis assumes that all nations adopt the same CO_2 emission charge schedule. Unfortunately, this is a highly unlikely outcome. The Kyoto Protocol, for example, sets emission reduction levels only for the developed and transition (Annex B) economies. The emissions of developing nations (classified as Non-Annex B), including China and India, are not constrained by the Protocol and at present there is no political agreement about how these nations might participate in a carbon regime of CO_2 emissions restraint.[16] Clearly if the fast growing developing economies do not adopt a carbon charge, the world level of emissions will grow faster than presented above.

To test the implications of lagged participation by emerging economies we explore two scenarios of delay in their adherence to CO_2 control regimes. They are shown in Figure 2.6. The *High CO_2 Price* trajectory from the earlier figures is repeated in the figure, and this price path is assumed to be followed by the Annex B parties. The trajectory marked *10-year Lag* has the developing economies maintaining a carbon charge that developed economies adopted ten years previously. The trajectory marked *Temp Lag* assumes that after 20 years the developing economies have returned to the carbon charge trajectory of the developed economies. In this latter case, developing economies would go through a transition period of a higher rate of increase in CO_2 prices than the 4% rate that is simulated for the developed economies and eventually (around 2045), the same CO_2 price level would be reached as in the case of universal participation. Note that these scenarios are not intended as realistic portrayals of potential future CO_2 markets. They simply provide a way to explore the implications of lagged accession to a climate agreement, however it might be managed.

Figure 2.7 projects the consequences of these different assumptions about the adherence of developing economies to a program of CO_2 penalties assuming the *Limited Nuclear* expansion and *EPPA-Ref Gas Price* path. First of all, the figure repeats the BAU case from before, and a case marked *High CO_2 Price,* which is the same scenario as before when all nations follow the *High CO_2 Price* path. The *Annex*

Table 2.9 Coal Capture and Sequestration Plants: Output (EJ) and Percentage of Coal Consumption

SCENARIO			BAU		LOW CO_2 PRICE	HIGH CO_2 PRICE
GAS	NUCLEAR	REGION	2000	2050	2050	2050
EPPA-Ref	Limited	Global	0	0	2.4 (4%)	29.2 (60%)
		US	0	0	0.1 (<1%)	9.4 (76%)
		China	0	0	1.8 (16%)	11.0 (88%)
EPPA-Ref	Expanded	Global	0	0	2.1 (4%)	22.5 (62%)
		US	0	0	0.1 (1%)	6.6 (86%)
		China	0	0	1.6 (18%)	8.5 (85%)
Low	Expanded	Global	0	0	2.1 (5%)	14.2 (52%)
		US	0	0	0.1 (<1%)	1.1 (22%)
		China	0	0	1.5 (36%)	8.2 (85%)

Assumes universal, simultaneous participation.

Table 2.10 Coal Price Index (2000 = 1)

SCENARIO			BAU		LOW CO_2 PRICE	HIGH CO_2 PRICE
GAS	NUCLEAR	REGION	2000	2050	2050	2050
EPPA-Ref	Limited	US	1.00	1.47	1.21	1.17
		China	1.00	1.60	1.24	1.14
EPPA-Ref	Expanded	US	1.00	1.39	1.14	1.08
		China	1.00	1.66	1.17	1.07
Low	Expanded	US	1.00	1.38	1.07	1.03
		China	1.00	1.64	1.08	1.01

Assumes universal, simultaneous participation.

Figure 2.6 Scenarios of Penalties on CO_2 Emissions: High Price for Annex B Nations and Two Patterns of Participation by Non-Annex B Parties *($/t CO_2)*

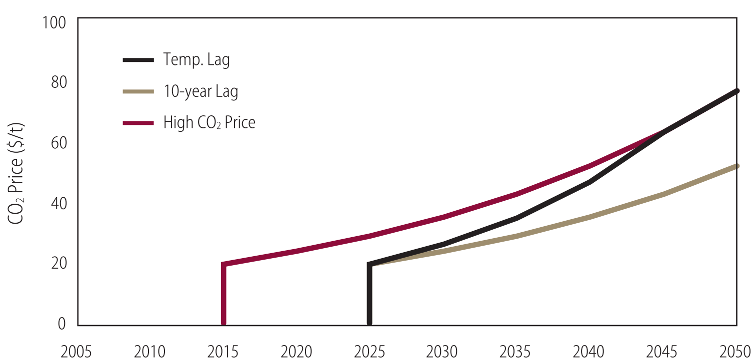
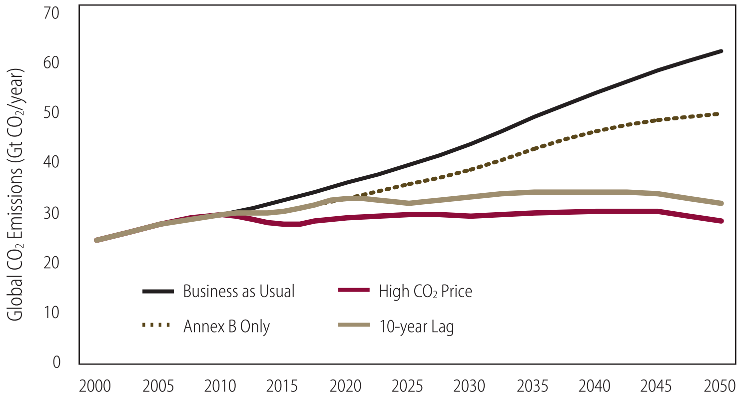


Figure 2.7 Global CO_2 Emissions under BAU and Alternative Scenarios for Non-Annex B Accession to the High CO_2 Price Path



B Only case considers the implications if the Non-Annex B parties never accept any CO_2 penalty, in which case total emissions continue to grow although at a slower pace than under BAU.

The next case assumes developing economies adhere to a "high" carbon price but with a lag of ten years after developed economies. The trend is clear: (1) if developing economies do not adopt a carbon charge, stabilization of emissions by 2050 cannot be achieved under this price path; and (2) if developing economies adopt a carbon charge with a time lag, stabilization is possible, but it is achieved at a later time and at a higher level of global emissions, depending upon the precise trajectory adopted by the developing economies. For example, if developing economies maintain a carbon tax with a lag of 10 years behind the developed ones, then cumulative CO_2 emissions through 2050 will be 123 $GtCO_2$ higher than if developing economies adopted the simulated carbon charge with no lag. If developing economies adopted the carbon tax with a ten-year lag but converged with the developed economies tax 20 years later (noted as *Temp Lag* in Figure 2.6 but not shown in Figure 2.7) then cumulative CO_2 emissions through 2050 would be 97 $GtCO_2$ higher than if developing economies adopted the tax with no lag. The significance of these degrees of delay can be understood in comparison with cumulative CO_2 emissions under the *High CO_2 Price* case over the period 2000 to 2050, which is estimated to be 1400 $GtCO_2$ under the projections used here.[17]

THE ROLE OF CCS IN A CARBON CONSTRAINED WORLD

The importance of CCS for climate policy is underlined by the projection for coal use if the same CO_2 emission penalty is imposed **and CCS is not available**, as shown in Table 2.11. Under *Limited Nuclear* expansion the loss of CCS would lower coal use in 2050 by some 28% but increase global CO_2 emissions by 14%. With *Expanded Nuclear* capacity, coal use and emissions are lower than in the limited nuclear case and the absence of CCS has the same effect. Depending on the nuclear assumption the loss of the CCS option would raise 2050 CO_2 emissions by between 10% and 15%.

This chart motivates our study's emphasis on coal use with CCS. Given our belief that coal will continue to be used to meet the world's energy needs, the successful adoption of CCS is critical to sustaining future coal use in a carbon-constrained world. More significantly considering the energy needs of developing countries, this technology may be an essential component of any attempt to stabilize global emissions of CO_2, much less to meet the Climate Convention's goal of stabilized atmospheric concentrations. This conclusion holds even for plausible levels of expansion of nuclear power or for policies stimulating the other approaches to emissions mitigation listed at the outset of this chapter.

CONCLUDING OBSERVATIONS

A central conclusion to be drawn from our examination of alternative futures for coal is that **if carbon capture and sequestration is successfully adopted, utilization of coal likely will expand even with stabilization of CO_2 emissions**. Though not shown here, extension of these emissions control scenarios further into the future shows continuing growth

Table 2.11 Coal Consumption (EJ) and Global CO_2 Emissions (Gt/yr) in 2000 and 2050 with and without Carbon Capture and Storage

	BAU		LIMITED NUCLEAR		EXPANDED NUCLEAR	
	2000	2050	WITH CCS	WITHOUT CCS	WITH CCS	WITHOUT CCS
Coal Use: Global	100	448	161	116	121	78
U.S.	24	58	40	28	25	13
China	27	88	39	24	31	17
Global CO_2 Emissions	24	62	28	32	26	29
CO_2 Emissions from Coal	9	32	5	9	3	6

Assumes universal, simultaneous participation, High CO_2 prices and EPPA-Ref gas prices.

in coal use provided CCS is available. Also to be emphasized is that market adoption of CCS requires the incentive of a significant and widely applied charge for CO_2 emissions.

All of these simulations assume that CCS will be available, and proven socially and environmentally acceptable, if and when more widespread agreement is reached on imposing a charge on CO_2 emissions. This technical option is not available in this sense today, of course. Many years of development and demonstration will be required to prepare for its successful, large scale adoption in the U.S. and elsewhere. A rushed attempt at CCS implementation in the face of urgent climate concerns could lead to excess cost and heightened local environmental concerns, potentially leading to long delays in implementation of this important option. Therefore these simulation studies underscore the need for development work now at a scale appropriate to the technological and societal challenge. The task of the following chapters is to explore the components of such a program—including generation and capture technology and issues in CO_2 storage—in a search for the most effective and efficient path forward.

CITATIONS AND NOTES

1. S. Ansolabehere et al., *The Future of Nuclear Power: An Intedisciplinary MIT Study,* 2003, Cambridge, MA. Found at: web.mit.edu/nuclearpower.
2. U.S. Department of Energy, Energy Information Administration, *International Energy Outlook 2006*, DOE/EIA-0484(2006) – referred to in the text as DOE/EIA IEO (2006).
3. U.S. Department of Energy, Energy Information Administration, *International Energy Annual 2004* (posted July 12, 2006).
4. In China there has been a history of multiple official estimates of coal production and upward revisions for previous years. Some government statistics show higher numbers for the 2003 and 2004 quantities in Tables 2.1 and 2.2.
5. This charge may be imposed as a result of a tax on carbon content or as the result of a cap-and-trade system that would impose a price on CO_2 emissions. In the remainder of the paper, the terms charge, price, tax, and penalty are used interchangeably to denote the imposition of a cost on CO_2 emissions.
6. The MIT EPPA model is described by Paltsev, S., J.M. Reilly, H.D. Jacoby, R.S. Eckaus, J. McFarland, M. Sarofim, M. Asadoorian & M. Babiker, The MIT Emissions Prediction and Policy Analysis (EPPA) Model: Version 4, MIT Joint Program on the Science and Policy of Global Change, Report No 125, August 2005. The model as documented there has been extended by the implementation of an improved representation of load dispatching in the electric sector—an improvement needed to properly assess the economics of CCS technology. It is assumed that all new coal plants have efficiencies corresponding to supercritical operation, that U.S. coal fired generation will meet performance standards for SO_2 and NOx, and Hg similar to those under the EPA's Clean Air Interstate Rule and Clean Air Mercury Rules.
7. The simulations shown here assume any revenues from taxes or auctioned permits are recycled directly to consumers. Alternative formulations, such as the use of revenues to reduce other distorting taxes, would have some effect on growth and emissions but would not change the insights drawn here from the comparison of policy cases.

8. The Kyoto targets are not imposed in either the projections of either the EIA or the EPPA simulations because the target beyond 2012 is not known nor are the methods by which the first commitment period targets might actually be met. Imposition of the existing Kyoto targets would have an insignificant effect on the insights to be drawn from this analysis. Note also that neither the EIA analyses nor the EPPA model are designed to try to represent short-term fluctuations in fuel markets, as occurred for example in the wake of supply disruptions in 2005.
9. National Commission on Energy Policy, *Ending the Energy Stalemate: A Bipartisan Strategy to Meet America's Energy Challenges*, December 2004.
10. The range of scenarios may be compared with the DOE/IEA IEO (2006), which projects nuclear generation of 3.29 million GWh in 2030 with no difference between its Reference, High and Low growth cases.
11. These paths for the U.S. may be compared with the DOE/IEA Annual Energy Outlook (2006) which projects a 65% increase in U.S. natural gas prices from 2000 to 2030, whereas EPPA projects a 100% rise over this period. On the other hand our Low price assumption shows 70% growth, very close to the AEO projection for the U.S.
12. In these EPPA calculations the focus is on emissions, but it is important to remember that higher emission levels translate into higher global mean greenhouse gas concentrations and it is the concentration of greenhouse gases that influences global climate. These carbon penalties succeed in stabilizing carbon emissions, not atmospheric concentrations which would continue to rise over the period shown in Figure 2.3.
13. The global 2050 biomass production of 48 EJ is expressed in the figure in liquid fuel units. The implied quantity of dry biomass input is approximately 120 EJ. Following the standard accounting convention, the global primary input to nuclear power is expressed in equivalent heat units of fossil electricity. Because fossil generation is becoming more (thermally) efficient in this projection nuclear power appears not to be increasing in the figure when in fact it is growing according to the "limited" case in Table 2.6. The same procedure is applied to hydroelectric and non-biomass renewable sources of electricity.
14. Calibration of the EPPA model has applied the official data on Chinese coal as reported in DOE/IEA IEO. Higher estimates of recent and current consumption are also available from Chinese government agencies (see Endnote 4) and if they prove correct then both Chinese and world coal consumption and emissions are higher than shown in these results. In addition, there is uncertainty in all these projections, but the uncertainty is especially high for an economy in rapid economic transition, like China.
15. The EPPA model projects a slightly more rapid coal price growth under these conditions than does the DOE/EIA. Its Annual Energy Outlook (2006) shows a 20% minemouth price increase 2000 to 2030 for the U.S., whereas EPPA projects about a 10% increase over this period.
16. The Kyoto regime permits "cooperative development measures" that allow Annex B countries to earn emission reduction credits by investing in CO_2 reduction projects in emerging economies. The quantitative impact that CDM might make to global CO_2 reductions is not considered in our study, and CDM credits are not included in this version of the EPPA model.
17. If official statistics of recent Chinese coal consumption prove to be an underestimate (see Endnotes 4 and 14), then very likely the emissions shown in Figure 2.6, importantly including the excess burden of a 10-year lag by developing countries, would be increased.

Chapter 3 — Coal-Based Electricity Generation

INTRODUCTION

In the U.S., coal-based power generation is expanding again; in China, it is expanding very rapidly; and in India, it appears on the verge of rapid expansion. In all these countries and worldwide, the primary generating technology is pulverized coal (PC) combustion. PC combustion technology continues to undergo technological improvements that increase efficiency and reduce emissions. However, technologies favored for today's conditions may not be optimum under future conditions. In particular, carbon dioxide capture and sequestration in coal-based power generation is an important emerging option for managing carbon dioxide emissions while meeting growing electricity demand, but this would add further complexity to the choice of generating technology.

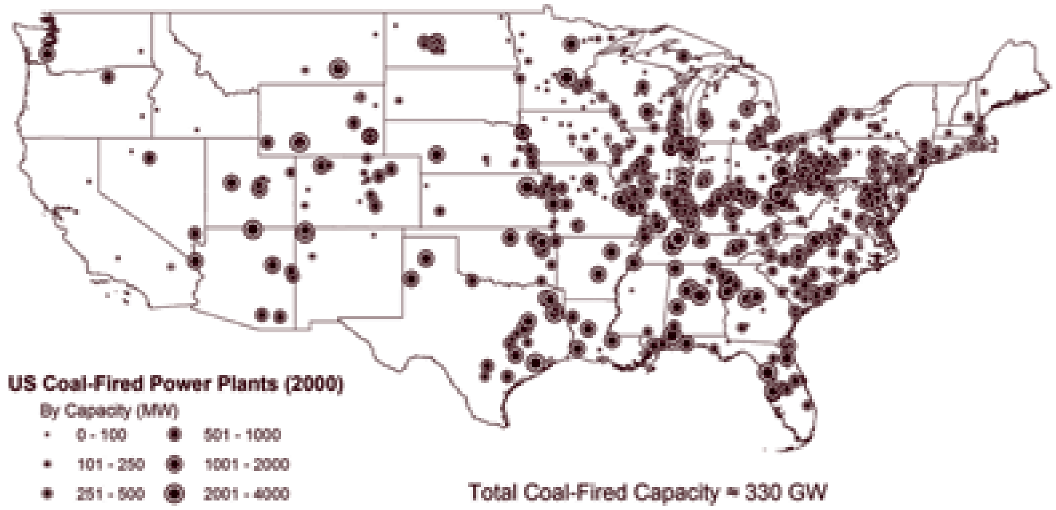
The distribution of coal-based generating plants for the U. S. is shown in Figure 3.1. Most of the coal-based generating units in the U. S. are between 20 and 55 years old; the average age of the fleet is over 35 years[1]. Coal-based generating units less than 35 years old average about 550 MW_e; older generating units are typically smaller. With current life-extension capabilities, many of these units could, on-average, operate another 30+ years. Units that are less than about 50 years old are essentially all air-blown, PC combustion units. The U.S. coal fleet average generating efficiency is about 33%, although a few, newer generating units exceed 36% efficiency [2][3]. Increased generating efficiency is important, since it translates directly into lower criteria pollutant emissions (at a given removal efficiency) and lower carbon dioxide emissions per kW_e-h of electricity generated.

GENERATING TECHNOLOGIES — OVERVIEW

This chapter evaluates the technologies that are either currently commercial or will be commercially viable in the near term for electricity generation from coal. It focuses primarily on the U. S., although the analysis is more broadly applicable. We analyze these generating technologies in terms of the cost of electricity produced by each, without and with carbon dioxide (CO_2) capture, and their applicability, efficiency, availability and reliability. Power generation from coal is subject to a large number of variables which impact technology choice, operating efficiency, and cost of electricity (COE) produced [4]. Our approach here was to pick a point set of conditions at which to compare each of the generating technologies, using a given generating unit design model to provide consistency. We then consider how changes from this point set of conditions, such as changing coal type, impact the design, operation, and cost of electricity (COE) for each technology. We also consider emissions control and retrofits for CO_2 capture for each technology. Appendix 3.A summarizes coal type and quality issues, and their impact.

For the technology comparisons in this chapter, each of the generating units considered was a green-field unit which contained all the emissions control equipment required to operate slightly below current, low, best-demonstrated criteria emissions performance levels.

Figure 3.1 Distribution of U. S. Coal-Based Power Plants. Data from 2002 USEPA eGRID database; Size Of Circles Indicate Power Plant Capacity.



To evaluate the technologies on a consistent basis, the design performance and operating parameters for these generating technologies were based on the Carnegie Mellon Integrated Environmental Control Model, version 5.0 (IECM) [5] which is a modeling tool specific to coal-based power generation [6] [7]. The units all use a standard Illinois # 6 bituminous coal, a high-sulfur, Eastern U.S. coal with a moderately high heating value (3.25 wt% sulfur & 25,350 kJ/kg (HHV)). Detailed analysis is given in Table A-3.B.1 [5] (Appendix 3.B).

GENERATING EFFICIENCY The fraction of the thermal energy in the fuel that ends up in the net electricity produced is the generating efficiency of the unit [8]. Typical modern coal units range in thermal efficiency from 33% to 43% (HHV). Generating efficiency depends on a number of unit design and operating parameters, including coal type, steam temperature and pressure, and condenser cooling water temperature [9]. For example, a unit in Florida will generally have a lower operating efficiency than a unit in northern New England or in northern Europe due to the higher cooling water temperature in Florida. The difference in generating efficiency could be 2 to 3 percentage points. Typically, units operated at near capacity exhibit their highest efficiency; unit cycling and operating below capacity result in lower efficiency.

LEVELIZED COST OF ELECTRICITY

The levelized cost of electricity (COE) is the constant dollar electricity price that would be required over the life of the plant to cover all operating expenses, payment of debt and accrued interest on initial project expenses, and the payment of an acceptable return to investors. Levelized COE is comprised of three components: capital charge, operation and maintenance costs, and fuel costs. Capital cost is generally the largest component of COE. This study calculated the capital cost component of COE by applying a carrying charge factor of 15.1% to the total plant cost (TPC). Appendix 3.C provides the basis for the economics discussed in this chapter.

AIR-BLOWN COAL COMBUSTION GENERATING TECHNOLOGIES

In the next section we consider the four primary air-blown coal generating technologies that compose essentially all the coal-based power generation units in operation today and being built. These include PC combustion using subcritical, supercritical, or ultra-supercritical steam cycles designed for Illinois #6 coal and circulating fluid-bed (CFB) combustion designed for lignite. Table 3.1 summariz-

Table 3.1 Representative Performance And Economics For Air-Blown PC Generating Technologies

	SUBCRITICAL PC		SUPERCRITICAL PC		ULTRA-SUPERCRITICAL PC		SUBCRITICAL CFB[6]	
	W/O CAPTURE	W/ CAPTURE	W/O CAPTURE	W/ CAPTURE	W/O CAPTURE	W/ CAPTURE	W/O CAPTURE	W/ CAPTURE
PERFORMANCE								
Heat rate (1), Btu/kW_e-h	9,950	13,600	8,870	11,700	7,880	10,000	9,810	13,400
Generating efficiency (HHV)	34.3%	25.1%	38.5%	29.3%	43.3%	34.1%	34.8%	25.5%
Coal feed, kg/h	208,000	284,000	185,000	243,000	164,000	209,000	297,000	406,000
CO_2 emitted, kg/h	466,000	63,600	415,000	54,500	369,000	46,800	517,000	70,700
CO_2 captured at 90%, kg/h (2)	0	573,000	0	491,000	0	422,000	0	36,000
CO_2 emitted, g/kW_e-h	931	127	830	109	738	94	1030	141
COSTS								
Total Plant Cost, \$/kW_e (3)	1,280	2,230	1,330	2,140	1,360	2,090	1,330	2,270
Inv.Charge, ¢/kW_e-h @ 15.1% (4)	2.60	4.52	2.70	4.34	2.76	4.24	2.70	4.60
Fuel, ¢/kW_e-h @ \$1.50/MMBtu	1.49	2.04	1.33	1.75	1.18	1.50	0.98	1.34
O&M, ¢/kW_e-h	0.75	1.60	0.75	1.60	0.75	1.60	1.00	1.85
COE, ¢/kW_e-h	**4.84**	**8.16**	**4.78**	**7.69**	**4.69**	**7.34**	**4.68**	**7.79**
Cost of CO_2 avoided[5] vs. same technology w/o capture, \$/tonne	41.3		40.4		41.1		39.7	
Cost of CO_2 avoided[5] vs. supercritical w/o capture, \$/tonne	48.2		40.4		34.8		42.8	

Basis: 500 MW_e net output. Illinois # 6 coal (61.2% wt C, HHV = 25,350 kJ/kg), 85% capacity factor

(1) efficiency = 3414 Btu/kW_e-h/(heat rate);
(2) 90% removal used for all capture cases
(3) Based on design studies and estimates done between 2000 & 2004, a period of cost stability, updated to 2005\$ using CPI inflation rate. 2007 cost would be higher because of recent rapid increases in engineering and construction costs, up 25 to 30% since 2004.
(4) Annual carrying charge of 15.1% from EPRI-TAG methodology for a U.S. utility investing in U.S. capital markets; based on 55% debt @ 6.5%, 45% equity @ 11.5%, 38% tax rate, 2% inflation rate, 3 year construction period, 20 year book life, applied to total plant cost to calculate investment charge
(5) Does not include costs associated with transportation and injection/storage
(6) CFB burning lignite with HHV = 17,400 kJ/kg and costing \$1.00/million Btu

es representative operating performance and economics for these air-blown coal combustion generating technologies. Appendix 3.C provides the basis for the economics. PC combustion or PC generation will be used to mean air-blown pulverized coal combustion for the rest of this report, unless explicitly stated to be oxy-fuel PC combustion for oxygen-blown PC combustion.

PULVERIZED COAL COMBUSTION POWER GENERATION: WITHOUT CO_2 CAPTURE

SUBCRITICAL OPERATION In a pulverized coal unit, the coal is ground to talcum-powder fineness, and injected through burners into the furnace with combustion air [10-12]. The fine coal particles heat up rapidly, undergo pyrolysis and ignite. The bulk of the combustion air is then mixed into the flame to completely burn the coal char. The flue gas from the boiler passes through the flue gas clean-up units to remove particulates, SO_x, and NO_x. The flue gas exiting the clean-up section meets criteria pollutant permit requirements, typically contains 10–15% CO_2 and is essentially at atmospheric pressure. A block diagram of a subcritical PC generating unit is shown in Figure 3.2. Dry, saturated steam is generated in the furnace boiler tubes and is heated further in the superheater section of the furnace. This high-pressure, superheated steam drives the steam turbine coupled to an electric generator. The low-pressure steam exiting the steam turbine is condensed, and the condensate pumped back to the boiler for conversion into steam. Subcritical operation refers to steam pressure and temperature below 22.0 MPa (~3200 psi) and about 550˚ C (1025° F) respectively. Subcritical PC units have generating efficiencies between 33 to 37% (HHV), dependent on coal quality, operations and design parameters, and location.

Key material flows and conditions for a 500 MW_e subcritical PC unit are given in Figure 3.2 [5, 13]. The unit burns 208,000 kg/h (208 tonnes/h [14]) of coal and requires about 2.5 million kg/h of combustion air. Emissions control was designed for 99.9% PM and 99+% SO_x reductions and greater than about 90% NO_x reduction. Typical subcritical steam cycle conditions are 16.5 MPa (~2400 psi) and 540° C (1000˚ F) superheated steam. Under these operating conditions (Figure 3.2), IECM projects an efficiency of 34.3% (HHV) [15]. More detailed material flows and operating conditions are given in Appendix 3.B, Figure A-3.B.2, and Table 3.1 summarizes the CO_2 emissions.

The coal mineral matter produces about 22,800 kg/h (23 tonnes/h) of fly and bottom ash. This can be used in cement and/or brick manufacture. Desulfurization of the flue gas produces about 41,000 kg/h (41 tonnes/h) of wet solids that may be used in wallboard manufacture or disposed of in an environmentally safe way.

SUPERCRITICAL AND ULTRA-SUPERCRITICAL OPERATION Generating efficiency is increased by designing the unit for operation at higher steam temperature and pressure. This represents a movement from subcritical to supercritical to ultra-supercritical steam parameters [16]. Supercritical steam cycles were not commercialized until the late 1960s, after the necessary materials technologies had been developed. A number of supercritical units were built in the U.S. through the 1970's and early 80's, but they were at the limit of the then-available materials and fabrication capabilities, and some problems were encountered [17]. These problems have been overcome for supercritical operating conditions, and supercritical units are now highly reliable. Under supercritical conditions, the supercritical fluid is expanded through the high-pressure stages of a steam turbine, generating electricity. To recharge the steam properties and increase the amount of power generated, after expansion through the high-pressure turbine stages, the

Figure 3.2 Subcritical 500 MW_e Pulverized Coal Unit without CO_2 Capture

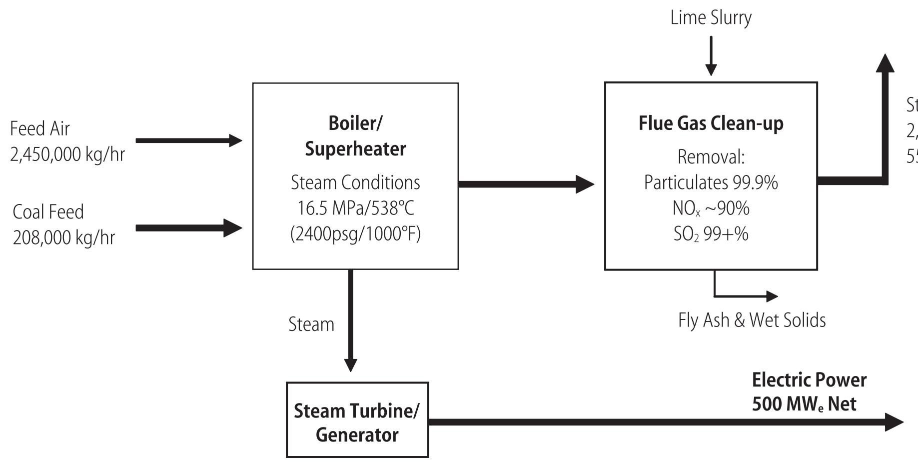
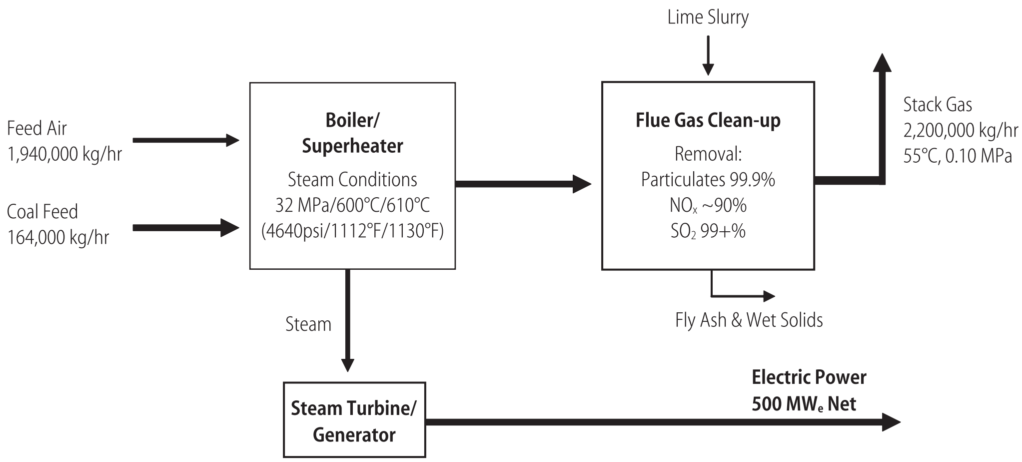


Figure 3.3 Ultra-Supercritical 500 MW_e Pulverized Coal Unit without CO_2 Capture



steam is sent back to the boiler to be reheated. Reheat, single or double, increases the cycle efficiency by raising the mean temperature of heat addition to the cycle.

Supercritical electricity generating efficiencies range from 37 to 40% (HHV), depending on design, operating parameters, and coal type. Current state-of-the-art supercritical PC generation involves 24.3 MPa (~3530 psi) and 565° C (1050° F), resulting in a generating efficiency of about 38% (HHV) for Illinois #6 coal.

Meanwhile, new materials capabilities have been further expanding the potential operating range. To take advantage of these developments, the power industry, particularly in Europe and Japan, continues to move to higher steam pressure and temperature, primarily higher temperatures. Operating steam cycle conditions above 565° C (>1050° F) are referred to as ultra-supercritical. A number of ultra-supercritical units operating at pressures to 32 MPa (~4640 psi) and temperatures to 600/610° C (1112-1130° F) have been constructed in Europe and Japan [18]. Operational availability of these units to date has been comparable to that of subcritical plants. Current materials research and development is targeting steam cycle operating conditions of 36.5 to 38.5 MPa (~5300-5600 psi) and temperatures of 700-720° C (1290-1330° F)[19]. These conditions should increase generating efficiency to the 44 to 46% (HHV) range for bituminous coal, but require further materials advances, particularly for manufacturing, field construction, and repair.

Figure 3.3 is a block diagram of a 500 MW_e ultra-supercritical PC generating unit showing key flows. The coal/combustion side of the boiler and the flue gas treatment are the same as for a subcritical boiler. Coal required to generate a given amount of electricity is about 21% lower than for subcritical generation, which means that CO_2 emissions per MW_e-h are reduced by 21%. The efficiency projected for these design operating conditions is 43.3% (HHV) (Figure 3.3) vs. 34.3% for subcritical conditions. More detailed material and operating information is given in Appendix 3.B. Table 3.1 summarizes the performance for subcritical, supercritical, and ultra-supercritical operation.

FLUID-BED COMBUSTION A variation on PC combustion is fluid-bed combustion in which coal is burned with air in a fluid bed, typically a circulating fluid bed (CFB)[20-22]. CFBs are best suited to low-cost waste fuels and low-quality or low heating value coals. Crushed coal and limestone are fed into the bed, where the limestone undergoes calcination to produce lime (CaO). The fluid bed consists mainly of lime, with a few percent coal, and recirculated coal char. The bed operates at significantly lower temperatures, about 427° C (800° F), which thermodynamically favors low NO_x formation and SO_2 capture by reaction with CaO to form $CaSO_4$. The steam cycle can be subcritical and potentially supercritical, as with PC combustion, and generating efficiencies are similar. The primary advantage of CFB technology is its capability to capture SO_2 in the bed, and its flexibility to a wide range of coal properties, including coals with low heating value, high-ash coals and low-volatile coals, and to changes in coal type during operation. Several new lignite-burning CFB units have been constructed recently, and CFBs are well suited to co-firing biomass [23].

The performance data for the CFB unit in Table 3.1 is based on lignite rather than Illinois # 6 coal. The lignite has a heating value of 17,400 kJ/kg and low sulfur. The coal feed rate is higher than for the other technologies because of the lower heating value of the lignite. Appendix 3.B gives a detailed process schematic for CFB generation.

COAL TYPE AND QUALITY EFFECTS

Coal type and quality impact generating unit technology choice and design, generating efficiency, capital cost, performance, and COE (Appendix 3.A). Boiler designs today usually encompass a broader range of typical coals than initially intended to provide future flexibility. Single coal designs are mostly limited to mine-mouth plants, which today are usually only lignite, subbituminous, or brown coal plants. The energy, carbon, moisture, ash, and sulfur contents, as well as ash characteristics, all play an important role in the value and selection of coal, in its transportation cost, and in the technology choice for power generation. For illustration, Table 3.2 gives typical values and ranges for various coal properties as a function of coal type. Although most of the studies available are based on bituminous coals, a large fraction of the power generated in the U.S. involves Western subbituminous coals (>35%), such as Powder River Basin, because of its low sulfur content.

Each of these coal properties interacts in a significant way with generation technology to affect performance. For example, higher sulfur content reduces PC generating efficiency due to the added energy consumption and operating costs to remove SO_x from the flue gas. High ash content requires PC design changes to manage erosion. High ash is a particular problem with Indian coals. Fluid-bed combustion is well suited to high-ash coals, low-carbon coal waste, and lignite. Several high-efficiency, ultra-supercritical and supercritical PC generating units have recently been commissioned in Germany burning brown coal or lignite, and several new CFB units have been constructed in Eastern Europe, the U.S., Turkey and India burning lignite and in Ireland burning peat[23, 24].

Coal types with lower energy content and higher moisture content significantly affect capital cost and generating efficiency. About 50% of U.S. coal is sub-bituminous or lignite. Using bituminous Pittsburgh #8 as the reference, PC units designed for Powder River Basin (PRB) coal and for Texas lignite have an estimated 14% and 24% higher capital cost respectively. Generating efficiency decreases but by a smaller percentage (Appendix 3.A, Figure A-3.A.3) [25]. However, the lower cost of coal types with lower heating value can offset the impact of this increased capital cost and decreased efficiency, thus, resulting in very little impact on COE. Using average 2004 mine-mouth coal prices and PC generation, the COE for Illinois #6, PRB, and Texas lignite is equal to or less than that for Pittsburgh #8 (Appendix 3.A, Figure A-3.A.4).

U.S. CRITERIA POLLUTANT IMPACTS

Although coal-based power generation has a negative environmental image, advanced PC plants have very low emissions; and PC emissions control technology continues to improve and will improve further (Appendix 3.D). It is not clear when and where the ultimate limits of flue gas control will be reached. In the U.S., particulate removal, via electrostatic precipita-

Table 3.2 Typical Properties of Characteristic Coal Types

COAL TYPE	ENERGY CONTENT, kJ/kg [CARBON CONTENT, wt %]	MOISTURE, wt %	SULFUR, wt %	ASH, wt %
Bituminous*	27,900 (ave. consumed in U.S.) [67 %]	3 – 13	2 – 4	7 - 14
Sub-bituminous* (Powder River Basin)	20,000 (ave. consumed in U.S.) [49 %]	28 - 30	0.3–0.5	5 - 6
Lignite*	15,000 (ave. consumed in U.S.) [40 %]	30 - 34	0.6 - 1.6	7 - 16
Average Chinese Coal	19,000 - 25,000 [48 – 61 %]	3 - 23	0.4 – 3.7	28 - 33
Average Indian Coal	13,000 – 21,000 [30 – 50 %]	4 - 15	0.2 – 0.7	30 - 50

** U.S coal reserves are ~ 48 % anthracite & bituminous, ~37 % subbituminous, and ~ 15 % lignite (See Appendix 3-A, Figure A.2 for more details.)*

tors (ESP) or fabric filters, is universally practiced with very high levels of removal (99.9%). Flue gas desulfurization has been added to less than one-third of U.S. coal-based generating capacity [2], and post-combustion NO_x control is practiced on about 10% of the coal-based generating capacity.

The Clean Air Act (1990) set up a cap and trade system for SO_x [26] and established emissions reductions guidelines for NO_x. This has helped produce a 38% reduction in total SO_x emissions over the last 30 years, while coal-based power generation grew by 90%. Total NO_x emissions have been reduced by 25% over this period. Recent regulations, including NAAQS[27], the Clean Air Interstate Rule (CAIR) [28], and the Clean Air Mercury Rule (CAMR) [29] will require an additional 60% reduction in total SO_x emissions and an additional 45% reduction in total NO_x emissions nationally by 2020. During this period, coal-based generation is projected to grow about 35%. Mercury reduction initially comes with SO_x abatement; additional, mandated reductions come after 2009. NAAQS have produced a situation in which permitting a new coal generating unit requires extremely low emissions of particulate matter (PM), SO_x, and NO_x, driven by the need to meet stringent, local air quality requirements, essentially independent of national emissions caps.

Newly permitted coal-fired PC units routinely achieve greater than 99.5% particulate control, and removal efficiencies greater than 99.9% are achievable at little additional cost. Wet flue-gas desulfurization (FGD) can achieve 95% SO_x removal without additives and 99% SO_x removal with additives [30]. Selective catalytic reduction (SCR), combined with low-NO_x combustion technology, routinely achieves 90+% NO_x reduction over non-controlled emissions levels. New, advanced PC units in the U.S. are currently achieving criteria pollutant emissions reductions consistent with the performance outlined above and have emissions levels that are at or below the emissions levels achieved by the best PC units in Japan and Europe (Appendix 3.D).

Today, about 25% of the mercury in the coal burned is removed by the existing flue gas treatment technologies in place, primarily with the fly ash via electrostatic precipitators (ESP) or fabric filters. Wet FGD achieves 40-60% mercury removal; and when it is combined with SCR, mercury removal could approach 95% for bituminous coals [31]. For subbituminous coals, mercury removal is typically less than 40%, and may be significantly less for lignite, even when the flue gas clean-up technologies outlined above are in use. However, with activated carbon or brominated activated carbon injection removal rates can be increased to ~90% [31]. Optimization of existing technologies and new technology innovations can be expected to achieve > 90% mercury removal on most if not all coals within the next 10-15 years.

Table 3.3 gives the estimated incremental impact on the COE of the flue gas treatment technologies to meet the low emissions levels that are the design basis of this study, vs. a PC unit without controls. The impact of achieving these levels of control is about 1.0 ¢/kW_e-h

Table 3.3 Estimated Incremental Costs for a Pulverized Coal Unit to Meet Today's Best Demonstrated Criteria Emissions Control Performance Vs. No Control

	CAPITAL COST[a] [$/kW$_e$]	O&M[b] [¢/kW$_e$-h]	COE[c] [¢/kW$_e$-h]
PM Control[d]	40	0.18	0.26
NO_x	25 (50 – 90)[e]	0.10 (0.05 – 0.15)	0.15 (0.15 – 0.33)
SO_2	150 (100 – 200)[e]	0.22 (0.20 – 0.25)	0.52 (0.40 – 0.65)
Incremental control cost	215	0.50	0.93[f]

a. Incremental capital costs for a typical, new-build plant to meet today's low emissions levels. Costs for low heating value coals will be somewhat higher

b . O&M costs are for typical plant meeting today's low emissions levels. Costs will be somewhat higher for high-sulfur and low heating value coals.

c. Incremental COE impact, bituminous coal

d. Particulate control by ESP or fabric filter included in the base unit costs

e. Range is for retrofits and depends on coal type, properties, control level and local factors

f. When added to the "no-control" COE for SC PC, the total COE is 4.78 ¢/kW$_e$-h

or about 20% of the total COE from a highly-controlled PC unit. Although mercury control is not explicitly addressed here, removal should be in the 60-80% range for bituminous coals, including Illinois #6 coal, and less for subbituminous coals and lignite. We estimate that the incremental costs to meet CAIR and CAMR requirements and for decreasing the PM, SO_x, and NO_x emissions levels by a factor of 2 from the current best demonstrated emissions performance levels used for Table 3.3 would increase the cost of electricity by about an additional 0.22 ¢/kW$_e$-h (Appendix 3.D, Table A-3D.4). The total cost of emissions control is still less than 25% of the cost of the electricity produced. Meeting the Federal 2015 emissions levels is not a question of control technology capabilities but of uniform application of current technology. Meeting local emissions requirements may be a different matter.

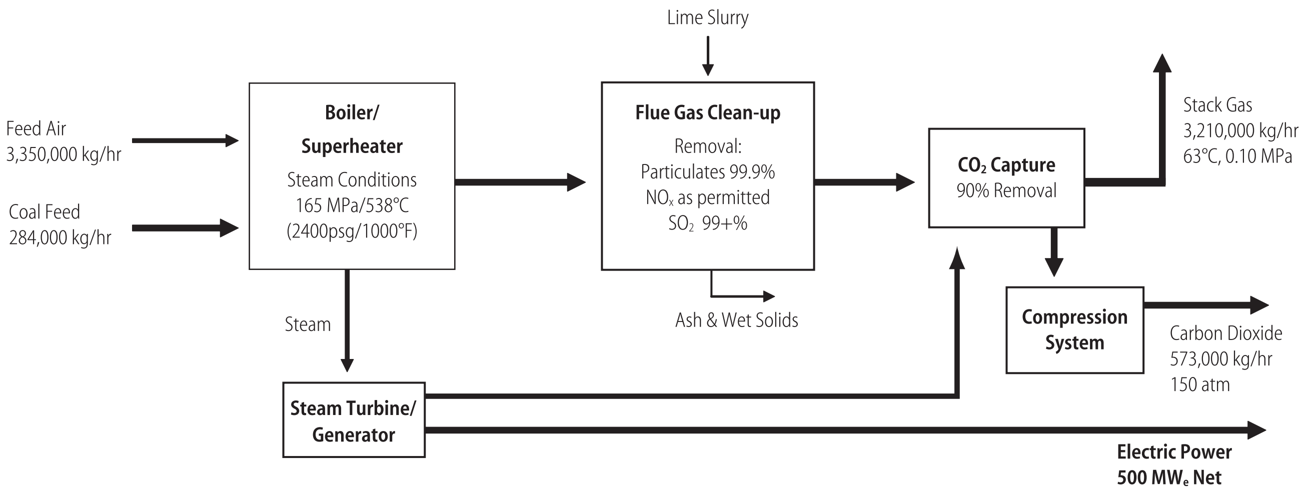
PULVERIZED COAL COMBUSTION GENERATING TECHNOLOGY: WITH CO_2 CAPTURE

CO_2 capture with PC combustion generation involves CO_2 separation and recovery from the flue gas, at low concentration and low partial pressure. Of the possible approaches to separation [32], chemical absorption with amines, such as monoethanolamine (MEA) or hindered amines, is the commercial process of choice [33, 34]. Chemical absorption offers high capture efficiency and selectivity for air-blown units and can be used with sub-, super-, and ultra-supercritical generation as illustrated in Figure 3.4 for a subcritical PC unit. The CO_2 is first captured from the flue gas stream by absorption into an amine solution in an absorption tower. The absorbed CO_2 must then be stripped from the amine solution via a temperature increase, regenerating the solution for recycle to the absorption tower. The recovered CO_2 is cooled, dried, and compressed to a supercritical fluid. It is then ready to be piped to storage.

CO_2 removal from flue gas requires energy, primarily in the form of low-pressure steam for the regeneration of the amine solution. This reduces steam to the turbine and the net power output of the generating plant. Thus, to maintain constant net power generation the coal input must be increased, as well as the size of the boiler, the steam turbine/generator, and the equipment for flue gas clean-up, etc. Absorption solutions that have high CO_2 binding energy are required by the low concentration of CO_2 in the flue gas, and the energy requirements for regeneration are high.

A subcritical PC unit with CO_2 capture (Figure 3.4), that produces 500 MW$_e$ net power, requires a 37% increase in plant size and in coal feed rate (76,000 kg/h more coal) vs. a

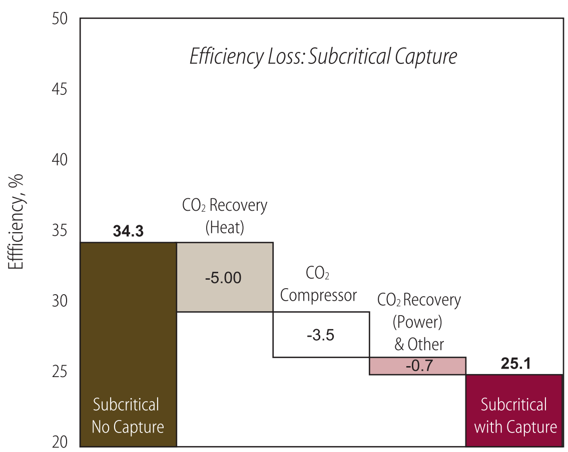
Figure 3.4 Subcritical 500 MW_e Pulverized Coal Unit with CO_2 Capture



500 MW_e unit without CO_2 capture (Figure 3.2). The generating efficiency is reduced from 34.3% to 25.1% (Table 3.1). The primary factors in efficiency reduction associated with addition of CO_2 capture are illustrated in Figure 3.5. The thermal energy required to recover CO_2 from the amine solution reduces the efficiency by 5 percentage points. The energy required to compress the CO_2 from 0.1 MPa to about 15 MPa (to a supercritical fluid) is the next largest factor, reducing the efficiency by 3.5 percentage points. All other energy requirements amount to less than one percentage point.

An ultra-supercritical PC unit with CO_2 capture (Figure 3.6) that produces the same net power output as an ultra-supercritical PC unit without CO_2 capture (Figure 3.3) requires a 27% increase in unit size and in coal feed rate (44,000 kg/h more coal). Figure 3.7 illustrates the main factors in efficiency reduction associated with addition of CO_2 capture to an ultra-supercritical PC unit. The overall efficiency reduction is 9.2 percentage points in both cases, but the ultra-supercritical, non-capture unit starts at a sufficiently high efficiency that with CO_2 capture, its efficiency is essentially the same as that of the subcritical unit without CO_2 capture.

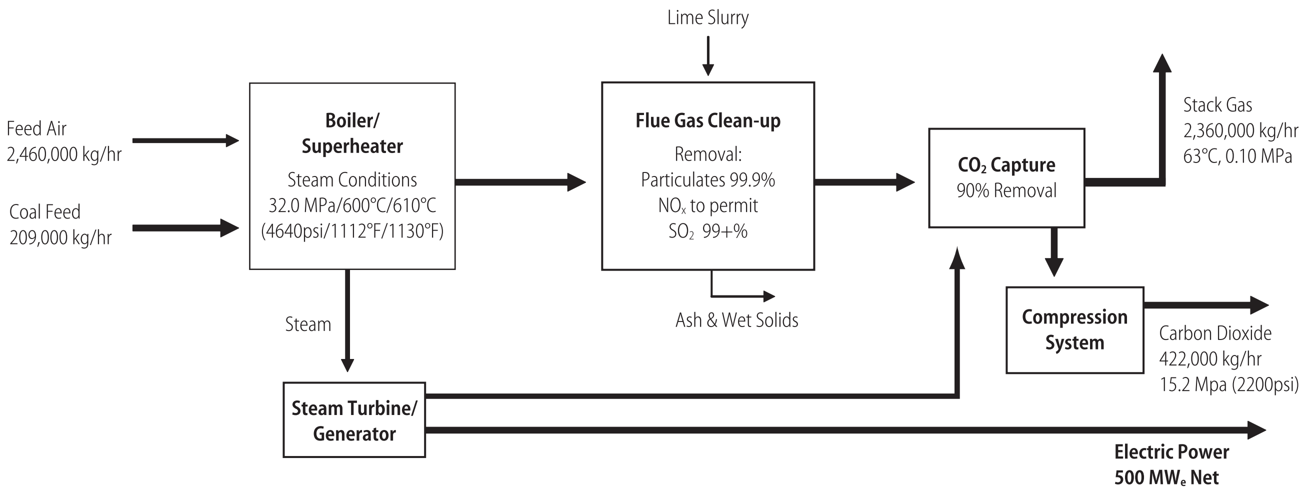
Figure 3.5 Parasitic Energy Requirements for a Subcritical Pulverized Coal Unit With Post-Combustion CO_2 Capture



COST OF ELECTRICITY FOR AIR-BLOWN PULVERIZED COAL COMBUSTION

The cost of electricity (COE), without and with CO_2 capture, was developed for the competing technologies analyzed in this report through a detailed evaluation of recent design studies, combined with expert validation. Appendix 3.C lists the studies that formed the basis for our report (Table A-3.C.2), provides more detail on each, and details the approach used. The largest and most variable component of COE among the studies is the capital charge, which is dependent on the total plant (or unit) cost (TPC) and the cost of capital. Figure 3.8 shows

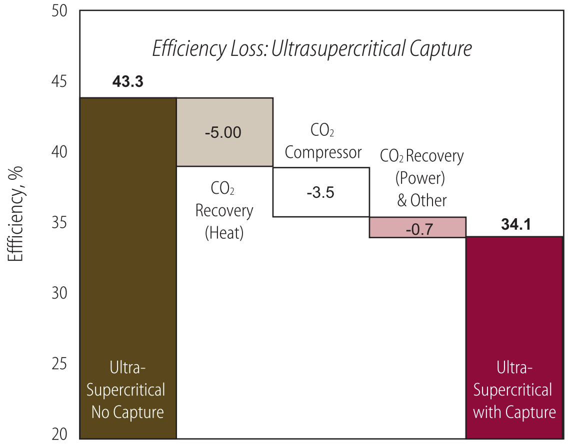
Figure 3.6 Ultra-Supercritical 500 MW_e Pulverized Coal Unit with CO_2 Capture



the min, max, and mean of the estimated TPC for each technology expressed in 2005 dollars. Costs are for a 500 MW_e plant and are given in $/$kW_e$ net generating capacity.

In addition to the variation in TPC, each of these studies used different economic and operating parameter assumptions resulting in a range in the capital carrying cost, in the O&M cost, and in the fuel cost. The differences in these assumptions among the studies account for much of the variability in the reported COE. The COE from these studies is shown in Figure 3.9, where the "as-reported" bars show the min, max, and mean in the COE for the different technologies as reported in the studies in the dollars of the study year. Appendix 3.C provides more detail.

Figure 3.7 Parasitic Energy Requirements for an Ultra-Supercritical Pulverized Coal Unit with Post-Combustion CO_2 Capture



To compare the studies on a more consistent basis, we recalculated the COE for each of the studies using the normalized economic and operating parameters listed in Table 3.4. O&M costs are generally considered to be technology and report-specific and were not changed in this analysis. Other factors that contribute to variation include regional material and labor costs, and coal quality impacts. The "normalized" bars in Figure 3.9 summarize the results of this analysis of these design studies.

The variation in "as-reported" COE for non-capture PC combustion is small because of the broad experience base for this technology. Significant variation in COE exists for the CO_2 capture cases due to the lack of commercial data. The normalized COE values are higher for most of the cases because we used a higher fuel price and put all cost components in 2005 dollars.

To develop the COE values for this report, we took the TPC numbers from the design studies (Figure 3.8), adjusted them to achieve internal consistency (e.g. SubC PC<SC PC<USC PC), then compared our TPC numbers with industry consensus group numbers [35] and made secondary adjustments based on ratios and deltas from these numbers. This produced the TPC values in Table 3.1. Using these TPC

numbers, the parameters in Table 3.4, and estimated O&M costs, we calculated the COE for each technology, and these are given in Table 3.1.

Total plant costs shown above and in Table 3.1 were developed during a period of price stability [2000-2004] and were incremented by CPI inflation to 2005$. These costs and the deltas among them were well vetted, broadly accepted, and remain valid in comparing costs of different generating technologies. However, significant cost inflation from 2004 levels due to increases in engineering and construction costs including labor, steel, concrete and other consumables used for power plant construction, has been between 25 and 30%. Thus, a SCPC unit with an estimated capital cost of $1330 (Table 3.1) is now projected at $1660 to $1730/ kW_e in 2007$. Because we have no firm data on how these cost increases will affect the cost of the other technologies evaluated in this report, the discussion that follows is based on the cost numbers in Table 3.1, which for relative comparison purposes remain valid.

For PC generation without CO_2 capture, the COE decreases from 4.84 to 4.69 ¢/kW_e-h from subcritical to ultra-supercritical technology because efficiency gains outweigh the additional capital cost (fuel cost component decreases faster than the capital cost component increases). Historically, coal cost in the U.S. has been low enough that the economic choice has been subcritical PC. The higher coal costs in Europe and Japan have driven the choice of higher-efficiency generating technologies, supercritical and more recently ultra-supercritical. For the CFB case, the COE is similar to that for the PC cases, but this is because cheaper lignite is the feed, and emissions control is less costly. The CFB design used here does not achieve the very low criteria emissions achieved by our PC design. For Illinois #6 and comparable emissions limits, the COE for the CFB would be significantly higher.

The increase in COE in going from no-capture to CO_2 capture ranges from 3.3 ¢/kW_e-h for subcritical generation to 2.7 ¢/kW_e-h for ultra-supercritical generation (Table 3.1). Over half of this increase is due to higher capital carrying charge resulting from the increased boiler and steam turbine size and the added CO_2 capture, recovery, and compression equipment. About two thirds of the rest is due to higher O&M costs associated with the increased operational scale per kW_e and with CO_2 capture and recovery. For air-blown PC combustion technologies, the cost of avoided CO_2 is about $41 per tonne. These costs are for capture, compression and drying, and do not include the pipeline, transportation and sequestration costs.

The largest cause of the efficiency reduction observed with CO_2 capture for air-blown PC generation (Figure 3.5 and 3.7) is the energy

Figure 3.8 Total Plant Cost for Air-Blown Coal Combustion Power Generation Technologies from Recent Design Studies. The Min, Max, and Mean (2005 Dollars) Are Shown When Multiple Studies Evaluated a Given Technology.

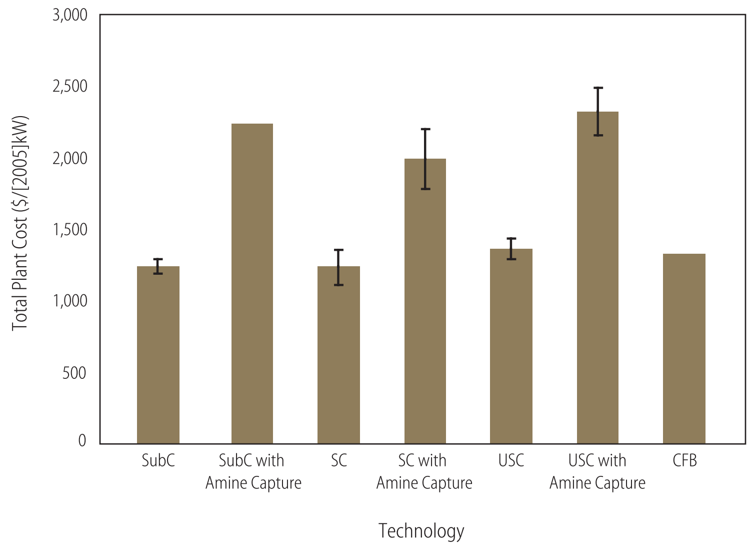
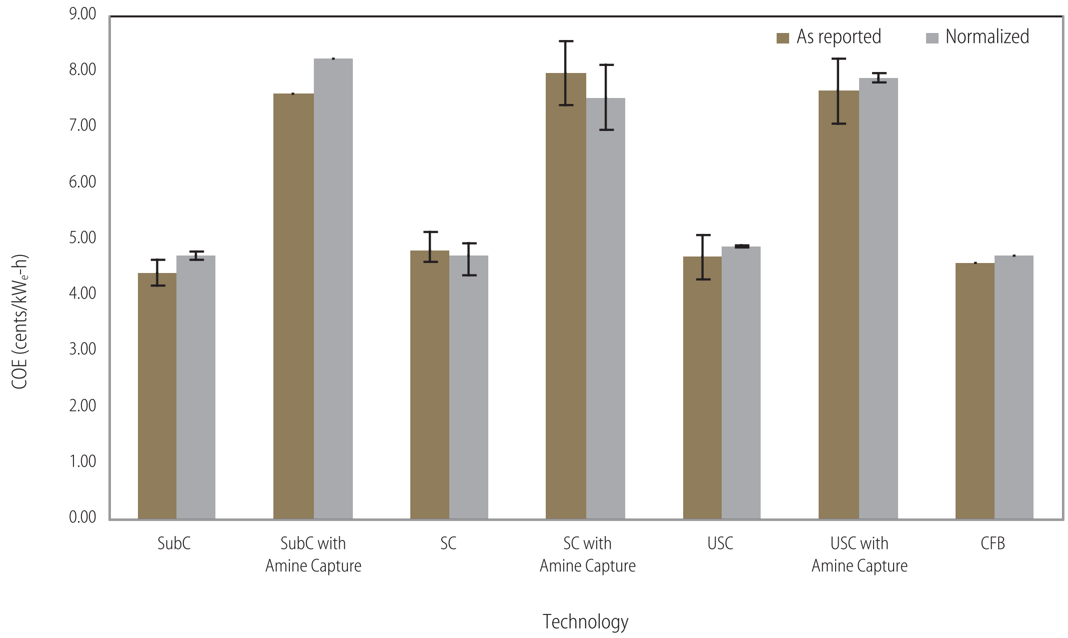


Table 3.4 Economic and Operating Parameters

PARAMETER	VALUE
Capacity factor	85%
Carrying charge factor	15.1%
Fuel cost	$1.50 / MMBtu (HHV)
Total capital requirement (TCR)	12% higher than total plant cost
Life of plant	20 years
Cost year basis	2005
Tax rate	39.2%

Figure 3.9 Cost of Electricity from Design Studies As-Reported and Using Normalized Economic and Operating Parameters for Air-Blown Coal Combustion Generating Technologies. Min, Max, and Mean (2005$) for Multiple Studies.



required to regenerate the amine solution (recovering the CO_2), which produces a 5 percentage point efficiency reduction. If this component could be reduced by 50% with an efficient, lower-energy capture technology, the COE for supercritical capture would be reduced by about 0.5 ¢/kW$_e$-h to about 7.2 ¢/kW$_e$-h and by about 0.4 ¢/kW$_e$-h for ultra-supercritical generation. This would reduce the CO_2 avoided cost to about $30 per tonne, a reduction of over 25%.

RETROFITS FOR CO_2 CAPTURE

Because of the large coal-based PC generating fleet in place and the additional capacity that will be constructed in the next two decades, the issue of retrofitting for CO_2 capture is important to the future management of CO_2 emissions. For air-blown PC combustion units, retrofit includes the addition of a process unit to the back end of the flue-gas system to separate and capture CO_2 from the flue gas, and to dry and compress the CO_2 to a supercritical fluid, ready for transport and sequestration. Since the existing coal fleet consists of primarily subcritical units, another option is to rebuild the boiler/steam system, replacing it with high efficiency supercritical or ultra-supercritical technology, including post-combustion CO_2 capture. Appendix 3.E provides a more-detailed analysis of retrofits and rebuilds.

For an MEA retrofit of an existing subcritical PC unit, the net electrical output can be derated by over 40%, e.g., from 500 MW$_e$ to 294 MW$_e$ [36]. In this case, the efficiency decrease is about 14.5 percentage points (Appendix 3.E) compared to about 9.2 percentage points for purpose-built subcritical PC units, one no-capture and the other capture (Table 3.1). With the retrofit, the steam required to regenerate the absorbing solution to recover the CO_2 (Figure 3.4), unbalances the rest of the plant so severely that the efficiency is reduced another 4 to 5 percentage points. In the retrofit case, the original boiler is running at full design capacity, but the original steam turbine is operating at about 60% design rating, which is well off its efficiency optimum. Due to the large power output reduction (41% derating), the retrofit capital cost is estimated to be $1600 per kW$_e$ [36]. This was for a specific unit with adequate space; however, retrofit costs are expected to be highly dependent on location and unit specifics. If the original unit is considered fully paid off, we estimate the COE after retrofit could be slightly less than that for a new purpose-built PC unit with CO_2 capture. However, an operating plant will usually have some residual value, and the reduction in unit efficiency and output, increased on-site space requirements and unit downtime are all complex factors not fully accounted for in this analysis. Based on our analysis, we conclude that retrofits seem unlikely.

Another approach, though not a retrofit, is to rebuild the core of a subcritical PC unit, installing supercritical or ultra-supercritical technology along with post-combustion CO_2 capture. Although the total capital cost for this approach is higher, the cost/kW_e is about the same as for a subcritical retrofit. The resultant plant efficiency is higher, consistent with that of a purpose-built unit with capture; the net power output can essentially be maintained; and the COE is about the same due to the overall higher efficiency. We estimate that an ultra-supercritical rebuild with MEA capture will have an efficiency of 34% and produce electricity for 6.91 ¢/kW_e-h (Appendix 3.E). We conclude that rebuilds including CO_2 capture appear more attractive than retrofits, particularly if they upgrade low-efficiency PC units with high-efficiency technology, including CO_2 capture.

CAPTURE-READY A unit can be considered capture-ready if, at some point in the future, it can be retrofitted for CO_2 capture and sequestration and still be economical to operate [37]. Thus, capture-ready design refers to designing a new unit to reduce the cost of and to facilitate adding CO_2 capture later or at least to not preclude addition of capture later. Capture-ready has elements of ambiguity associated with it because it is not a specific design, but includes a range of investment and design decisions that might be undertaken during unit design and construction. Further, with an uncertain future policy environment, significant pre-investment for CO_2 capture is typically not economically justified [38]. However, some actions make sense. Future PC plants should employ the highest economically efficient technology and leave space for future capture equipment if possible, because this makes retrofits more attractive. Siting should consider proximity to geologic storage.

OXYGEN-BLOWN COAL-BASED POWER GENERATION

The major problems with CO_2 capture from air-blown PC combustion are due to the need to capture CO_2 from flue gas at low concentration and low partial pressure. This is mainly due to the large amount of nitrogen in the flue gas, introduced with the combustion air. Another approach to CO_2 capture is to substitute oxygen for air, essentially removing most of the nitrogen. We refer to this as oxy-fuel PC combustion. A different approach is to gasify the coal and remove the CO_2 prior to combustion. Each of these approaches has advantages and disadvantages, but each offers opportunities for electricity generation with reduced CO_2-capture costs. We consider these approaches next in the form of oxy-fuel PC combustion and Integrated Gasification Combined Cycle (IGCC) power generation.

Table 3.5 summarizes representative performance and economics for oxygen-blown coal-based power generation technologies. Oxy-fuel combustion and IGCC were evaluated using the same bases and assumptions used for the PC combustion technologies (Table 3.1). In this case the estimates are for the N^{th} unit or plant where N is a relatively small number, < 10. In this report, we use gasification and IGCC to mean oxygen-blown gasification or oxygen-blown IGCC. If we mean air-blown gasification, it will be explicitly stated.

OXY-FUEL PULVERIZED COAL (PC) COMBUSTION

This approach to capturing CO_2 from PC units involves burning the coal with ~95%

Table 3.5 Representative Performance and Economics for Oxy-Fuel Pulverized Coal and IGCC Power Generation Technologies, Compared with Supercritical Pulverized Coal

	SUPERCRITICAL PC		SC PC-OXY	IGCC	
	W/O CAPTURE	W/ CAPTURE	W/CAPTURE	W/O CAPTUREQ	W/CAPTURE
PERFORMANCE					
Heat rate (1), Btu/kW_e-h	8,868	11,652	11,157	8,891	10,942
Generating efficiency (HHV)	38.5%	29.3%	30.6%	38.4%	31.2%
Coal feed, kg/h	184,894	242,950	232,628	185,376	28,155
CO_2 emitted, kg/h	414,903	54,518	52,202	415,983	51,198
CO_2 captured at 90%, kg/h (2)	0	490,662	469,817	0	460,782
CO_2 emitted, g/kW_e-h (2)	830	109	104	832	102
COSTS					
Total Plant Cost (3), $/$kW_e$	1,330	2,140	1,900	1,430	1,890
Inv. Charge, ¢/kW_e-h @ 15.1% (4)	2.70	4.34	3.85	2.90	3.83
Fuel, ¢/kW_e-h @ $1.50/MMBtu	1.33	1.75	1.67	1.33	1.64
O&M, ¢/kW_e-h	0.75	1.60	1.45	0.90	1.05
COE, ¢/kW_e-h	**4.78**	**7.69**	**6.98**	**5.13**	**6.52**
Cost of CO_2 avoided vs. same technology w/o capture (5), $/tonne		**40.4**	**30.3**		**19.3**
Cost of CO_2 avoided vs. supercritical technology w/o capture (5), $/tonne		**40.4**	**30.3**		**24.0**

Basis: *500 MW_e plant net output, Illinois # 6 coal (61.2 wt % C, HHV = 25,350 kJ/kg), & 85% capacity factor; for oxy-fuel SC PC CO_2 for sequestration is high purity; for IGCC, GE radiant cooled gasifier for no-capture case and GE full-quench gasifier for capture case.*

(1) efficiency = (3414 Btu/kW_e-h)/(heat rate)

(2) 90% removal used for all capture cases

(3) Based on design studies done between 2000 & 2004, a period of cost stability, updated to 2005$ using CPI inflation rate. Refers to the N^{th} plant where N is less than 10. 2007 cost would be higher because of recent rapid increases of engineering and construction costs, up to 30% since 2004.

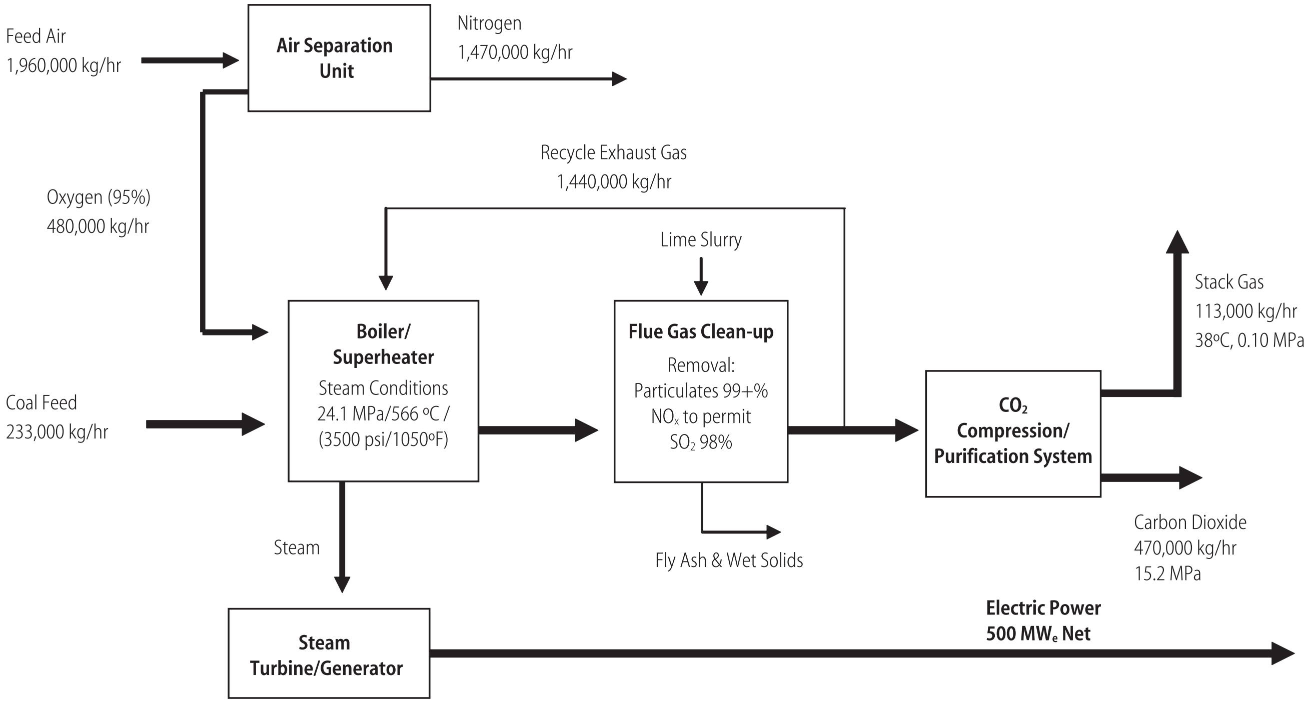
(4) Annual carrying charge of 15.1% from EPRI-TAG methodology, based on 55% debt @ 6.5%, 45% equity @ 11.5%, 39.2% tax rate, 2% inflation rate, 3 year construction period, 20 year book life, applied to total plant cost to calculate investment charge

(5) Does not include costs associated with transportation and injection/storage

pure oxygen instead of air as the oxidant[39-41]. The flue gas then consists mainly of carbon dioxide and water vapor. Because of the low concentration of nitrogen in the oxidant gas (95% oxygen), large quantities of flue gas are recycled to maintain design temperatures and required heat fluxes in the boiler, and dry coal-ash conditions. Oxy-fuel enables capture of CO_2 by direct compression of the flue gas but requires an air-separation unit (ASU) to supply the oxygen. The ASU energy consumption is the major factor in reducing the efficiency of oxy-fuel PC combustion. There are no practical reasons for applying oxy-fuel except for CO_2 capture.

A block diagram of a 500 MW_e oxy-fuel generating unit is shown in Figure 3.10 with key material flows shown. Boiler and steam cycle are supercritical. The coal feed rate is higher than that for supercritical PC without capture because of the power consumption of the air separation unit but lower than that for a supercritical PC with MEA CO_2 capture (Table 3.1). In this design, wet FGD is used prior to recycle to remove 95% of the SO_x to avoid boiler corrosion problems and high SO_x concentration in the downstream compression/separation equipment. Non-condensables are removed from the compressed flue gas via a two-stage flash. The composition requirements (purity) of the CO_2 stream for transport and geological injection are yet to be established. The

Figure 3.10 500 MW_e Supercritical Oxy-Fuel Generating Unit with CO_2 Capture



generating efficiency is 30.6% (HHV), which is about 1 percentage point higher than supercritical PC with MEA CO_2 capture. Current design work suggests that the process can be further simplified with SO_x and NO_x removal occurring in the downstream compression & separation stage at reduced cost [42]. Further work is needed.

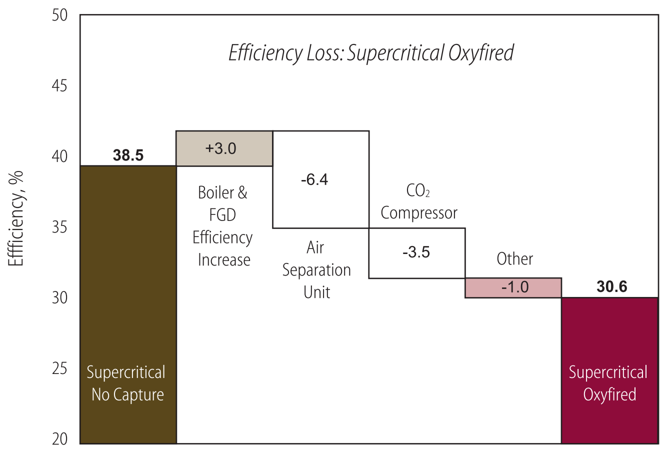
Figure 3.11 shows the parasitic energy requirements for oxy-fuel PC generation with CO_2 capture. Since the steam cycle is supercritical for the oxy-fuel case, supercritical PC is used as the comparison base. The oxy-fuel PC unit has a gain over the air-driven PC case due to improved boiler efficiency and reduced emissions control energy requirements, but the energy requirement of the ASU, which produces a 6.4 percentage point reduction, outweighs this efficiency improvement. The overall efficiency reduction is 8.3 percentage points from supercritical PC. More efficient oxygen separation technology would have a significant impact.

A key unresolved issue is the purity requirements of the supercritical CO_2 stream for geological injection (sequestration). Our design produces a highly-pure CO_2 stream, similar to that from the PC capture cases, but incurs additional cost to achieve this purity level. If this additional purification were not required for transport and geologic sequestration of the CO_2, oxy-fuel PC combustion could gain up to one percentage point in efficiency, and the COE could be reduced by up to 0.4 ¢/kW_e-h.

Oxy-fuel PC combustion is in early commercial development but appears to have considerable potential. It is under active pilot-scale development [43, 44]; Vattenfall plans a 30 MW_{th} CO_2-free coal combustion plant for 2008 start-up[43]; Hamilton, Ontario is developing a 24 MW_e oxy-fuel electricity generation project [45]; and other projects can be expected to be announced.

ECONOMICS Because there is no commercial experience with oxy-fuel combustion and lack of specificity on CO_2 purity requirements for transport and sequestration in a future regulatory regime, the TPC in the limited design studies ranged broadly [13, 39, 41, 46] (Appendix 3.C, Table A-3.C.2, Figure A-3.C.1).

Figure 3.11 Parasitic Energy Requirement for Oxy-Fuel Pulverized Coal Generation with CO_2 Capture Vs. Supercritical PC without CO_2 Capture



Only the Parsons study estimated the COE [13]. As with PC combustion, we reviewed the available design studies (Appendix 3.C), our plant component estimate of costs, and external opinion of TPC to arrive at a projected TPC (Table 3.5). We estimated generating efficiency to be 30.6% from the Integrated Environmental Control Model[5]. We applied our normalization economic and operating parameters (Table 3.4) to calculate a COE of 6.98 ¢/kW$_e$-h (Table 3.5). There may be some upside potential in these numbers if supercritical CO_2 stream purity can be relaxed and design efficiencies gained, but more data are needed.

RETROFITS Oxy-fuel is a good option for retrofitting PC and FBC units for capture since the boiler and steam cycle are less affected by an oxy-fuel retrofit; the major impact being an increased electricity requirement for the auxiliaries, particularly the ASU. Bozzuto estimated a 36% derating for an oxy-fuel retrofit vs. a 41% derating for MEA capture on the same unit [36]. In summary, the oxy-fuel retrofit option costs about 40% less on a \$/kW$_e$ basis, is projected to produce electricity at 10% to 15% less than an MEA retrofit, and has a significantly lower CO_2 avoidance cost (Appendix 3.E). Oxy-fuel rebuild to improve efficiency is another option and appears to be competitive with a high-efficiency MEA rebuild [47].

INTEGRATED GASIFICATION COMBINED CYCLE (IGCC)

Integrated gasification combined cycle (IGCC) technology produces electricity by first gasifying coal to produce syngas, a mixture of hydrogen and carbon monoxide[48, 49]. The syngas, after clean-up, is burned in a gas turbine which drives a generator. Turbine exhaust goes to a heat recovery generator to raise steam which drives a steam turbine generator. This combined cycle technology is similar to the technology used in modern natural gas fired combined-cycle power plants. Appendix 3.B provides more detail on gasification.

The key component in IGCC is the gasifier, for which a number of different technologies have been developed and are classified and summarized in Table 3.6.

Gasifier operating temperature depends on whether the ash is to be removed as a solid, dry ash or as a high-temperature liquid (slag). Outlet temperature depends on the flow regime and extent of mixing in the gasifier. For the current IGCC plants, oxygen-blown, entrained-flow gasifiers are the technology of choice, although other configurations are being evaluated.

Four 275 to 300 MW$_e$ coal-based IGCC demonstration plants, which are all in commercial operation, have been built in the U.S. and in Europe, each with government financial support [50][33]. Five large IGCC units (250 to 550 MW$_e$) are operating in refineries gasifying asphalt and refinery wastes [51, 52]; a smaller one (180 MW$_e$) is operating on petroleum coke. The motivation for pursuing IGCC is the potential for better environmental performance at a lower marginal cost, easier CO_2 capture for sequestration, and higher efficiency. However, the projected capital cost (discussed below) and operational availability of today's IGCC technology make it difficult to compete with conventional PC units at this time.

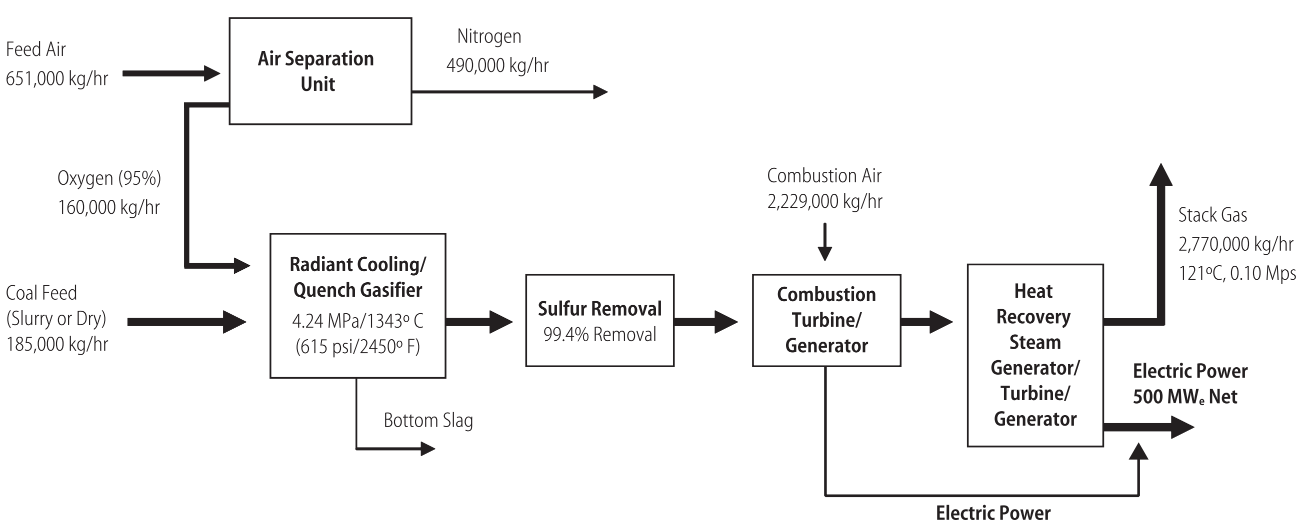
Table 3.6 Classification and Characteristics of Gasifiers			
	MOVING BED	FLUID BED	ENTRAINED FLOW
Outlet temperature	Low (425-600 °C)	Moderate (900-1050 °C)	High (1250-1600 °C)
Oxidant demand	Low	Moderate	High
Ash conditions	Dry ash or slagging	Dry ash or agglomerating	Slagging
Size of coal feed	6-50 mm	6-10 mm	< 100 µm
Acceptability of fines	Limited	Good	Unlimited
Other characteristics	Methane, tars and oils present in syngas	Low carbon conversion	Pure syngas, high carbon conversion

IGCC: WITHOUT CO_2 CAPTURE

There are several commercial gasifiers which can be employed with IGCC [53] (see Appendix 3.B for details). A block diagram of a 500 MW_e IGCC unit using a radiant cooling/quench gasifier is shown in Figure 3.12. Finely ground coal, either dry or slurried with water, is introduced into the gasifier, which is operated at pressures between 3.0 and 7.1 MPa (440 to 1050 psi), along with oxygen and water. Oxygen is supplied by an air separation unit (ASU). The coal is partially oxidized raising the temperature to between 1340 and 1400 °C. This assures complete carbon conversion by rapid reaction with steam to form an equilibrium gas mixture that is largely hydrogen and carbon monoxide (syngas). At this temperature, the coal mineral matter melts to form a free-flowing slag. The raw syngas exits the gasification unit at pressure and relatively high temperature, with radiative heat recovery raising high-pressure steam. Adequate technology does not exist to clean-up the raw syngas at high temperature. Instead, proven technologies for gas clean-up require near-ambient temperature. Thus, the raw syngas leaving the gasifier can be quenched by injecting water, or a radiant cooler, and/or a fire-tube (convective) heat exchanger may be used to cool it to the required temperature for removal of particulate matter and sulfur.

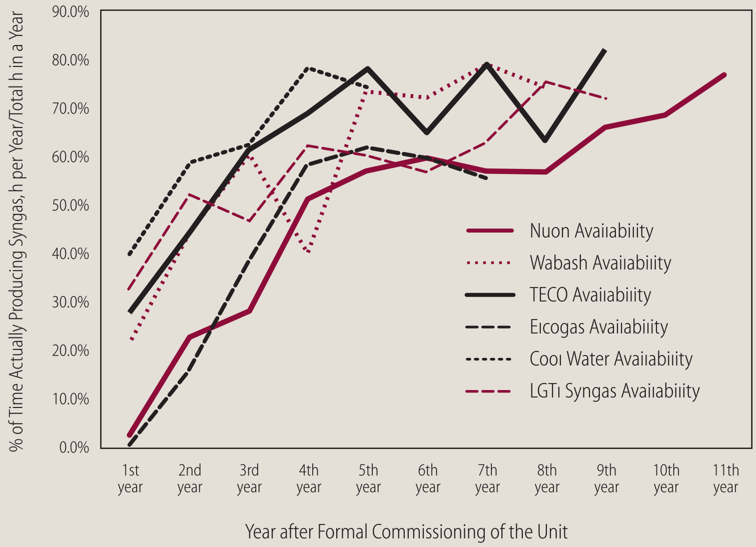
The clean syngas is then burned in the combustion turbine. The hot turbine exhaust gas is used to raise additional steam which is sent to the steam turbine in the combined-cycle power block for electricity production. For the configuration shown (See Box 3.1), the overall generating efficiency is 38.4% (HHV), but coal and gasifier type will impact this number.

Figure 3.12 500 MW_e IGCC Unit without CO_2 Capture



BOX 3.1 IGCC DEMONSTRATIONS

Figure Box 3.1 IGCC Availability History *(excluding operation on back-up fuel*



Graph provided by Jeff Phillips, EPRI {24}

The Cool Water Project sponsored by Southern California Edison in cooperation with GE and Texaco pioneered IGCC with support from the Synthetic Fuels Corporation. This plant demonstrated the feasibility of using IGCC to generate electricity. The plant operated periodically from 1984–1989, and cost over \$2000 /kW$_e$. The project was eventually abandoned, but it provided the basis for the Tampa Electric Polk Power Station. The DOE supported the 250 MW$_e$ Polk Station commercial IGCC demonstration unit, using a Texaco gasifier, which started up in 1996. The total plant cost was about \$1800/kW$_e$. Since it was the first commercial-scale IGCC plant, several optional systems were added, such as a hot-gas clean-up system, which were never used, and were later simplified or removed. When these changes are taken into accounted, the adjusted total plant cost has been estimated at \$1650/kWe (2001\$). This experience has led to some optimism that costs will come down significantly with economies of scale, component standardization, and technical and design advances. However, price increases will raise the nominal cost of plant capital significantly.

The availability of these early IGCC plants was low for the first several years of operation due to a range of problems, as shown in the figure. Many of the problems were design and materials related which were corrected and are unlikely to reappear; others are process related, much like running a refinery, but all eventually proved to be manageable. Gasifier availability is now 82+% and operating efficiency is ~35.4%. DOE also supported the Wabash River Gasification Repowering Project, an IGCC demonstration project using the Dow E-gas gasifier. This demonstration started up in late 1995, has 262 MW$_e$ capacity, and an efficiency of ~38.4%. Start-up history was similar to that of the Polk unit. LGTI provided the basis for Wabash.

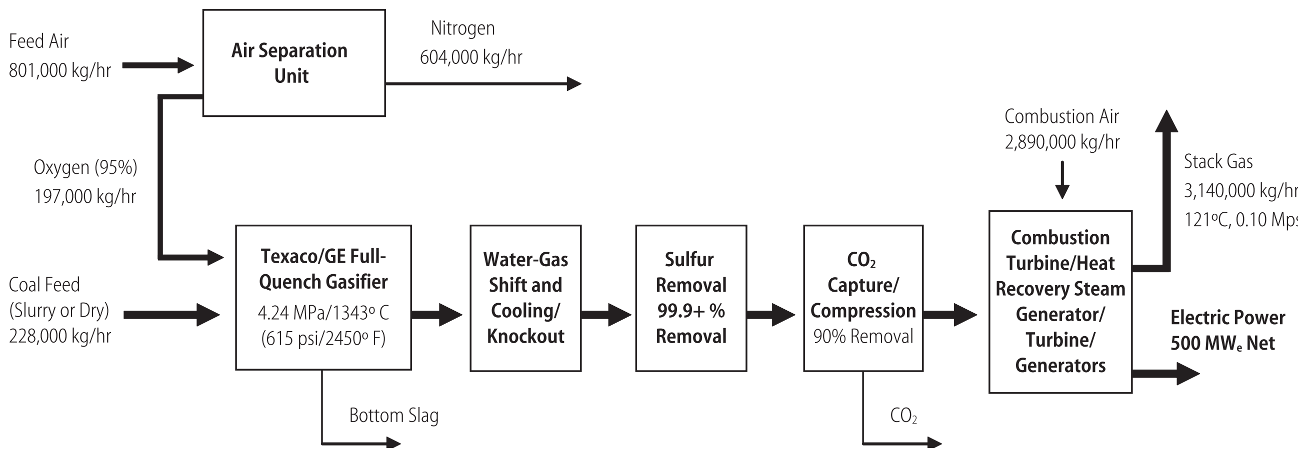
IGCC: WITH PRE-COMBUSTION CO_2 CAPTURE

Applying CO_2 capture to IGCC requires three additional process units: shift reactors, an additional CO_2 separation process, and CO_2 compression and drying. In the shift reactors, CO in the syngas is reacted with steam over a catalyst to produce CO_2 and hydrogen. Because the gas stream is at high pressure and has a high CO_2 concentration, a weakly CO_2-binding physical solvent, such as the glymes in Selexol, can be used to separate out the CO_2. Reducing the pressure releases the CO_2 and regenerates the solvent, greatly reducing the energy requirements for CO_2 capture and recovery compared to the MEA system. Higher pressure in the gasifier improves the energy efficiency of both the separation and CO_2 compression steps. The gas stream to the turbine is now predominantly hydrogen, which requires turbine modifications for efficient operation.

The block diagram with key material flows for a 500 MW$_e$ IGCC unit designed for CO_2 capture is shown in Figure 3.13. For CO_2 capture, a full-quench gasifier is currently considered the optimum configuration. The overall generating efficiency is 31.2% which is a 7.2 percentage point reduction from the IGCC system without CO_2 capture. Adding CO_2 capture requires a 23% increase in the coal feed rate. This compares with coal feed rate increases of 27% for ultra-supercritical PC and 37% for subcritical PC when MEA CO_2 capture is used.

Figure 3.14 illustrates the major impacts on efficiency of adding CO_2 capture to IGCC. CO_2 compression and water gas shift each have

Figure 3.13 500 MW_e IGCC Unit with CO_2 Capture



significant impacts. CO_2 compression is about two-thirds that for the PC cases because the CO_2 is recovered at an elevated pressure. Energy is required in the form of steam for shift reaction. The energy required for CO_2 recovery is lower than for the PC case because of the higher pressures and higher CO_2 concentrations, resulting in less energy intensive separation processes. The total efficiency reduction for IGCC is 7.2 percentage points as compared with 9.2 percentage points for the PC cases. This smaller delta between the no-capture and the capture cases is one of the attractive features of IGCC for application to CO_2 capture.

COST OF ELECTRICITY We analyzed the available IGCC design studies, without and with CO_2 capture, just as we did for PC generation, to arrive at a TPC and our estimate of the COE (Appendix 3.C). There was considerable variation (~\$400/kW_e from min to max) in the TPC from the design studies for both no-capture and capture cases as shown in Figure A-3.C.2 (Appendix 3.C). Each estimate is for a 500 MW_e plant and includes the cost of a spare gasifier. This variation is not surprising in that the studies involved two gasifier types, and there is little commercial experience against which to benchmark costs. There is a variation (min to max) of 0.8 ¢/kW_e-h for no capture and 0.9 ¢/kW_e-h for CO_2 capture in the "as-reported" COE in the studies (Figure A-3.C.4, Appendix 3.C).

We used the same approach to estimate the COE for IGCC as for air-blown PC [54]. For IGCC w/o capture, the COE is about 0.4 cent/kW_e-h higher than for supercritical PC generation, driven by somewhat higher capital and operating costs. The increase in COE for IGCC when CO_2 capture is added is about 1.4 ¢/kW_e-h. This is about half the increase projected for amine capture with supercritical PC. The cost of avoided CO_2 is about \$ 20 per tonne which is about half that for air-blown PC technology. Oxy-fuel PC is in between air-blown PC with amine capture and IGCC with CO_2 capture, based on currently available data.

The COE values developed for this report compare well with the "normalized" values

Figure 3.14 Parasitic Energy Requirement for IGCC with Pre-Combustion CO_2 Capture

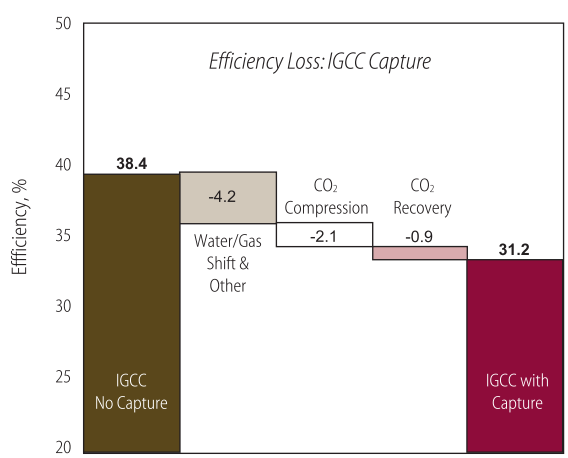


Table 3.7 Relative Cost of Electricity from PC and IGCC Units, without and with CO_2 Capture*

	MIT	GTC	AEP	GE
PC no-capture, reference	1.0	1.0	1.0	1.0
IGCC no-capture	1.05	1.11	1.08	1.06
IGCC capture	1.35	1.39	1.52	1.33
PC capture	1.60	1.69	1.84	1.58

**Included are: the MIT Coal Study results (MIT), the Gasification Technology Council (GTC) [56], General Electric (GE) [57], and American Electric Power (AEP) [58].*

from the design studies evaluated (Figure A-3.C.3 and A-3.C.4). Our values are close to the mean values for super-critical PC without and with capture. For IGCC, our values are at the high end of the range of the other design studies. Our COE for oxy-fuel PC is slightly higher than the "as-reported" values, although it is important to note that oxy-fuel data are based on only two published studies [44, 55].

To further validate the findings in this section, we compared our results with the COE estimates from several sources and summarize these results in Table 3.7. Supercritical PC without capture is set as the reference at 1.0. This suggests that without CO_2 capture, the cost of electricity from IGCC will be from 5 to 11% higher than from supercritical PC. When CO_2 capture is considered, the cost of electricity produced by IGCC would be increased by 30 to 50% over that of supercritical PC without capture, or 25 to 40% over that of IGCC without capture (Table 3.7). However, for supercritical PC with CO_2 capture, the cost of electricity is expected to increase by 60 to 85% over the cost for supercritical PC without capture. These numbers are for green-field plants; they are also for the Nth plant where N is less than 10; and they are based on cost estimates from the relatively stable 2000–2004 cost period.

COAL TYPE AND QUALITY EFFECTS Although gasification can handle almost any carbon-containing material, coal type and quality can have a larger effect on IGCC than on PC generation. IGCC units operate most effectively and efficiently on dry, high-carbon fuels such as bituminous coals and coke. Sulfur content, which affects PC operation, has little effect on IGCC cost or efficiency, although it may impact the size of the sulfur clean-up process. For IGCC plants, coal ash consumes heat energy to melt it, requires more water per unit carbon in the slurry, increases the size of the ASU, and ultimately results in reduced overall efficiency. This is more problematic for slurry-feed gasifiers, and therefore, high-ash coals are more suited to dry-feed systems (Shell), fluid-bed gasifiers (BHEL), or moving-bed gasifiers (Lurgi)[25]. Slurry-fed gasifiers have similar problems with high-moisture coals and coal types with low heating values, such as lignite. These coal types decrease the energy density of the slurry, increase the oxygen demand, and decrease efficiency. Dry-feed gasifiers are favored for high-moisture content feeds.

Coal quality and heating value impact IGCC capital cost and generating efficiency more strongly than they affect these parameters for PC generation (see Figure A-3.A.3, Appendix 3.A) [25]. However, the lower cost of coals with low heating value can offset much of the impact of increased capital cost and reduced efficiency. To illustrate, the capital cost per kW_e and the generating efficiency for an E-Gas IGCC plant designed for Texas lignite are estimated to be 37% higher and 24% lower respectively than if the unit were designed for Pittsburgh #8 coal [25]. For PC combustion the impact is significantly less: 24% higher and 10% lower respectively. As a result, we estimate that the COE for Texas lignite generation is about 20% higher (Figure A-3.A.4) than for Pittsburgh #8 coal because lower coal cost is not sufficient to offset the other increases.

Texas lignite has a high-moisture content and a low-carbon content, which is particularly bad for a slurry-feed gasifier. For a dry-feed gasifier, such as the Shell gasifier, the lignite would compare more favorably. Optimum gasifier type and configuration are influenced by coal type and quality, but there are limited data on these issues.

The available data illustrate several important trends and gaps. First, there is a lack of data and design studies for IGCC with low-heating value, low-quality coals and particularly for gasifiers other than water-slurry fed, entrained-flow systems. Second, PC generation without CO_2 capture is slightly favored over IGCC (lower COE) for high heating value, bituminous coals, but this gap increases as PC steam cycle efficiency increases and as coal heating value decreases. The COE gap is substantially widened (favoring PC) for coals with low heating values, such as lignite. Third, for CO_2 capture, the COE gap for high-heating value bituminous coals is reversed and is substantial (IGCC now being favored); but as coal heating value decreases, the COE gap is substantially narrowed. It appears that ultra-supercritical PC combustion and lower energy consuming CO_2 capture technology, when developed, could have a lower COE than water-slurry fed IGCC with CO_2 capture. This area needs additional study.

U.S. CRITERIA POLLUTANT IMPACTS – ENVIRONMENTAL PERFORMANCE IGCC has inherent advantages with respect to emissions control. The overall environmental footprint of IGCC is smaller than that of PC because of reduced volume and lower leachability of the fused slag, reduced water usage and the potential for significantly lower levels of criteria pollutant emissions. Criteria emissions control is easier because most clean-up occurs in the syngas which is contained at high pressure and has not been diluted by combustion air, i.e. nitrogen. Thus, removal can be more effective and economical than cleaning up large volumes of low-pressure flue gas.

The two operating IGCC units in the U.S. are meeting their permitted levels of emissions, which are similar to those of PC units. However, IGCC units that have been designed to do so can achieve almost order-of-magnitude lower criteria emissions levels than typical current U.S. permit levels and 95+% mercury removal with small cost increases. Appendix 3.D details the environmental performance demonstrated and expected.

Our point COE estimates suggest that although improvements in PC emissions control technology, including mercury control, will increase the COE from PC units, the levels of increased control needed to meet federal emissions levels for 2015 should not make the COE from a PC higher than that from an IGCC. We estimate that the increased emissions control to meet the U.S. 2015 regulations, including mercury, will increase the PC COE by about 0.22 ¢/kW_e-h to 5.00 ¢/kW_e-h and the COE for IGCC to 5.16 ¢/kW_e-h (Appendix 3.D). This does not include the cost of emissions allowances or major, unanticipated regulatory or technological changes. Although the COE numbers for PC and IGCC are expected to approach one another, the cost of meeting criteria pollutant and mercury emissions regulations should not force a change in technology preference from PC to IGCC without CO_2 capture.

However, evaluation and comparison of generating technologies for future construction need to incorporate the effect of uncertainty in the key variables into the economic evaluation. This includes uncertainty in technology performance, including availability and ability to cycle, and cost, in regulatory changes, including timing and cost, and in energy costs and electricity demand/dispatch. Forward estimates for each variable are set, values, bounds and probabilities are established; and a Monte Carlo simulation is done producing a sensitivity analysis of how changes in the variables affect the economics for a given plant. This analysis shows that as permitted future pollutant emissions levels are reduced and the cost of emissions control increases, the NPV cost gap between PC and IGCC will narrow; and at some point, increased emissions control can be expected to lead to IGCC having the lower NPV cost. This, of course, depends on when and the extent to which these changes occur and on how emissions control technology costs change with time and increasing reduction requirements. This type of analysis is used widely in evaluating the commercial economics of large capital projects, of which generation is a set, but is outside the scope of this report.

The same analysis applies to consideration of future CO_2 regulations. The introduction of a CO_2 tax at a future date (dependent on date of imposition, CO_2 tax rate, rate of increase, potential grandfathering and retrofit costs) will drive IGCC to be the lowest NPV cost alternative at some reasonable set of assumptions, and assuming today's technology performance. Substantial technology innovation could change the outcome, as could changing the feed from bituminous coal to lignite.

In light of all these considerations, it is clear that there is no technology today that is an obvious silver bullet.

RETROFITS FOR CO_2 CAPTURE Retrofitting an IGCC for CO_2 capture involves changes in the core of the gasification/combustion/power generation train that are different than the type of changes involved in retrofitting a PC plant for capture. The choice of the gasifier (slurry feed, dry feed), gasifier configuration (full-quench, radiant cooling, convective syngas coolers), acid gas clean-up, operating pressure, and gas turbine are dependent on whether a no-capture or a capture plant is being built. Appendix 3.E treats IGCC retrofitting in more detail.

No-capture designs tend to favor lower pressure [2.8 to 4.1 MPa (400–600 psi)] and increased heat recovery from the gasifier train (radiant coolers and even syngas coolers) to raise more steam for the steam turbine, resulting in a higher net generating efficiency. Dry feed (Shell) provides the highest efficiency and is favored for coals with lower heating value, largely because of their higher moisture content; but the capital costs are higher. On the other hand, capture designs favor higher-pressure [6.0 MPa (1000 psi)] operation, slurry feed, and full-quench mode[59]. Full-quench mode is the most effective method of adding sufficient steam to the raw syngas for the water gas shift reaction without additional, expensive steam raising equipment and/or robbing steam from the steam cycle. Higher pressure reduces the cost of CO_2 capture and recovery, and of CO_2 compression. In addition, the design of a high-efficiency combustion turbine for high hydrogen concentration feeds is different from combustion turbines optimized for syngas, requires further development, and has very little operating experience. In summary, an optimum IGCC unit design for no CO_2 capture is quite different from an optimum unit design for CO_2 capture.

Although retrofitting an IGCC unit for capture would involve significant changes in most components of the unit if it is to result in an optimum CO_2-capture unit, it appears that an IGCC unit could be successfully retrofit by addressing the key needed changes (adding shift reactors, an additional Selexol unit, and CO_2 compression/drying). In this case, retrofitting an IGCC unit would appear to be less expensive than retrofitting a PC unit, although it would not be an optimum CO_2-capture unit. Pre-investment for later retrofit will generally be unattractive and will be unlikely for a technology that is trying to establish a competitive position. However, for IGCC, additional space could be set aside to facilitate future retrofit potential. In addition, planning for a possible retrofit for capture could influence initial design choices (e.g., radiant quench vs. full quench).

IGCC OPERATIONAL HISTORY In addition to cost, IGCC has to overcome the perception of poor availability and operability. Appendix 3.B provides more detail, beyond that discussed below. For each of the current IGCC demonstration plants, 3 to 5 years was required to reach 70 to 80% availability after commercial operation was initiated. Because of the complexity of the IGCC process, no single process unit or component of the total system is responsible for the majority of the unplanned shutdowns that these units have experienced, reducing IGCC unit availability. However, the gasification complex or block has been the largest factor in reducing IGCC availability and operability. Even after reaching 70 to 80% availability, operational performance has not typically exceeded 80% consistently. A detailed analysis of the operating history of the Polk Power Station over the last few years suggests that it is very similar to operating a petroleum refinery, requiring continuous attention to avert, solve and prevent mechanical, equipment and process problems that periodically arise. In this sense, the operation of an IGCC unit is significantly different from the operation of a PC unit, and requires a different operational philosophy and strategy.

The Eastman Chemical Coal Gasification Plant uses a Texaco full-quench gasifier and a backup gasifier (a spare) and has achieved less than 2% forced outage from the gasification/syngas system over almost 20 years operation. Sparing is one approach to achieving better online performance, and a vigorous equipment health maintenance and monitoring program is another. There are five operating in-refinery IGCC units based on petroleum residuals and/or coke; two are over 500 MW_e each. Several other refinery-based gasification units produce steam, hydrogen, synthesis gas, and power. They have typically achieved better operating performance, more quickly than the coal-based IGCC units. Three more are under construction. It is fair to say that IGCC is well established commercially in the refinery setting. IGCC can also be considered commercial in the coal-based electricity generation setting, but in this setting it is neither well established nor mature. As such, it is likely to undergo significant change as it matures.

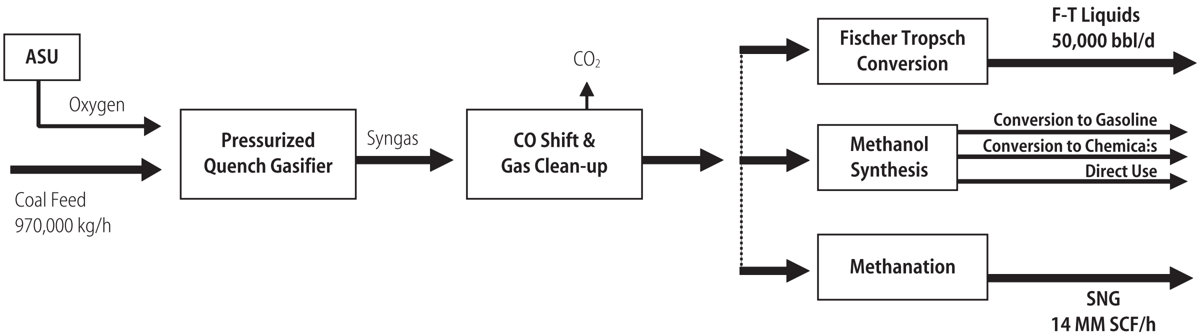
Our analysis assumes that IGCC plants, with or without capture, can "cycle" to follow load requirements. However, there is relatively little experience with cycling of IGCC plants (although the 250 MW_e Shell IGCC at Buggenum operated for 2 years in a load following mode under grid dispatch in the general range 50–100% load, and the Negishi IGCC unit routinely cycles between 100 to 75% load, both up and down, in 30 min) so considerable uncertainty exists for these performance features. Because an IGCC plant is "integrated" in its operation any shortfall in this performance could cause considerable increase in both variable and capital cost.

COAL TO FUELS AND CHEMICALS

Rather than burning the syngas produced by coal gasification in a combustion turbine, it can be converted to synthetic fuels and chemicals. The syngas is first cleaned of particulates and sulfur compounds and undergoes water gas shift to obtain the desired hydrogen to CO ratio. Fischer-Tropsch technology can be used to convert this syngas or "synthesis gas" into predominantly high-quality diesel fuel, along with naphtha and LPG. Fischer-Tropsch technology involves the catalytic conversion of the hydrogen and carbon monoxide in the synthesis gas into fuel range hydrocarbons. This technology has been used in South Africa since the 1950's, and 195,000 barrels per day of liquid fuels are currently being produced in that country by Fischer-Tropsch. Synthesis gas can also be converted to methanol which can be used directly or be upgraded into high-octane gasoline. For gaseous fuels production, the synthesis gas can be converted into methane, creating synthetic natural gas (SNG). Figure 3.15 illustrates three potential coal to fuels or chemicals process options. This type of process configuration could be called a coal refinery. More details are presented in Appendix 3.F.

Methanol production from coal-based synthesis gas is also a route into a broad range of chemicals. The naphtha and lighter hydrocarbons produced by Fischer-Tropsch are another route to produce a range of chemicals, in addition to the diesel fuel produced. The largest commodity chemical produced from

Figure 3.15 Coal to Liquid Fuels, Synthetic Natural Gas and Chemicals



synthesis gas today is ammonia. Although most U.S. ammonia plants were designed to produce their syngas by reforming natural gas, world wide there are a significant number of ammonia plants that use syngas from coal gasification and more are under construction. These routes to chemicals are easily integrated into a coal refinery, as is power generation. Commercially, these processes will be applied to the extent that they make economic sense and are in the business portfolio of the operating company.

For such a coal refinery, all the carbon entering in the coal exits as carbon in the fuels or chemicals produced, or as CO_2 in concentrated gas form that could easily be compressed for sequestration. In this case, of order 50% to 70% of the carbon in the coal would be in the form of CO_2 ready for sequestration. If the gasification product were hydrogen, then essentially all the carbon entering the refinery in the coal would appear in concentrated CO_2 streams that could be purified and compressed for sequestration. Without carbon capture and sequestration (CCS), we estimate that the Fischer-Tropsch fuels route produces about 150% more CO_2 as compared with the use of the petroleum-derived fuel products. For SNG, up to 175% more CO_2 is emitted than if regular natural gas is burned. With CCS, the full fuel-cycle CO_2 emissions for both liquid fuel and SNG are comparable with traditional production and utilization methods. Fortunately, CCS does not require major changes to the process, large amounts of additional capital, or significant energy penalties because the CO_2 is a relatively pure byproduct of the process at intermediate pressure. CCS requires drying and compressing to supercritical pressure. As a result of this the CO_2 avoided cost for CCS in conjunction with fuels and chemicals manufacture from coal is about one third of the CO_2 avoided cost for IGCC.

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1. NETL, *Power Plant Aging Characterization*. 2002.
2. NETL, *NETL Coal Power Database; Update for 2000 Operations, Technical and Performance Baseline*. 2002, NETL.
3. Average generating efficiency of the U.S. coal fleet was determined from the EIA Electric Power Annual Review (2003) by dividing the total MWe-h of coal-based electricity generated by the coal consumed in generating that power. This efficiency has been invarient from 1992 to 2003. NETL (2002) gives coal fleet plant efficency as a function of plant age.
4. In the U.S., the generating technology choice depends upon a number of issues, including: cost, criteria pollutant limits, coal type, efficiency, plant availability requirements, plant location (elevation and temperature) and potential for carbon dioxide regulations.
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7. Other modeling tools could have been used. Each would have given somewhat different results because of the myriad of design and parameter choices, and engineering approximations included in each. Model results are consistent with other models when operational differences are accounted for (Appendix 3-B).

8. U.S. engineering pracitce is to use the higher heating value (HHV) of the fuel in calculating generating efficiency, and electrical generating efficiencies are expressed on an HHV basis. Fuel prices are also normally quoted on an HHV basis. The HHV of a fuel includes the heat recovered in condensing the water formed in combustion to liquid water. If the water is not condensed, less heat is recovered; and the value is the Lower Heating Value (LHV) of the fuel.

9. Of these variables, steam cycle severity (steam temperature and pressure) is the most important. Steam cycle severity increases from subcritical to supercritical to ultra-supercritical. Increasing severity means that the steam carries more available energy to the steam turbine, resulting in higher generating efficiency.

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15. Changes in operating parameters, excluding emissions control levels, can shift the generating efficiency by upwards to one percentage point. Large changes in emissions control levels can have a similarly large effect. A conservative set of parameters was used in this study, giving a generating efficiency somewhat below the midpoint of the range. See Appendix 3-B and Appendix 3-D for more detail.

16. As steam pressure and temperature are increased above 218 atm (3200 psi) and 375° C (706° F), respectively, the water-steam system becomes supercritical. Under these conditions the two-phase mixture of liquid water and gaseous steam disappears. Instead with increasing temperature the fluid phase undergoes gradual transition from a single dense liquid-like phase to a less dense vapor-like phase, characterized by its own unique set of physical properties.

17. However, due to materials-related boiler tube fatigue and creep stress in headers, steamlines, and in the turbines, the utility industry moved back to subcritical technology for new U. S. coal power plants. Even after the materials problems were resolved there was not a move back to supercritical PC because at the very cheap price of U. S. coal, the added plant cost could not be justified on coal feed rate savings.

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