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, 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 kWe-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 (CO2) 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 CO2 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.
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-
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.

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

<table>
<thead>
<tr>
<th></th>
<th>SUBCRITICAL PC</th>
<th>SUPERCritical PC</th>
<th>ULTRA-SUPERCritical PC</th>
<th>SUBCRITICAL CFB*</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>W/O CAPTURE</td>
<td>W/ CAPTURE</td>
<td>W/O CAPTURE</td>
<td>W/ CAPTURE</td>
</tr>
<tr>
<td><strong>PERFORMANCE</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Heat rate (1), Btu/kW-h</td>
<td>9,950</td>
<td>13,600</td>
<td>8,870</td>
<td>11,700</td>
</tr>
<tr>
<td>Generating efficiency (HHV)</td>
<td>34.3%</td>
<td>25.1%</td>
<td>38.5%</td>
<td>29.3%</td>
</tr>
<tr>
<td>Coal feed, kg/h</td>
<td>208,000</td>
<td>284,000</td>
<td>185,000</td>
<td>243,000</td>
</tr>
<tr>
<td>CO2 emitted, kg/h</td>
<td>466,000</td>
<td>63,600</td>
<td>415,000</td>
<td>54,500</td>
</tr>
<tr>
<td>CO2 captured at 90%, kg/h (2)</td>
<td>0</td>
<td>573,000</td>
<td>0</td>
<td>491,000</td>
</tr>
<tr>
<td>CO2 emitted, g/kW-h (2)</td>
<td>931</td>
<td>127</td>
<td>830</td>
<td>109</td>
</tr>
<tr>
<td><strong>COSTS</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total Plant Cost, $/kW (3)</td>
<td>1,280</td>
<td>2,230</td>
<td>1,330</td>
<td>2,140</td>
</tr>
<tr>
<td>Inv. Charge, ¢/kW-h @ 15.1% (4)</td>
<td>2.60</td>
<td>4.52</td>
<td>2.70</td>
<td>4.34</td>
</tr>
<tr>
<td>Fuel, ¢/kW-h @ $1.50/MMBtu</td>
<td>1.49</td>
<td>2.04</td>
<td>1.33</td>
<td>1.75</td>
</tr>
<tr>
<td>O&amp;M, ¢/kW-h</td>
<td>0.75</td>
<td>1.60</td>
<td>0.75</td>
<td>1.60</td>
</tr>
<tr>
<td>COE, ¢/kW-h</td>
<td>4.84</td>
<td>8.16</td>
<td>4.78</td>
<td>7.69</td>
</tr>
<tr>
<td>Cost of CO2 avoided(5) vs. same technology w/o capture, $/tonne</td>
<td>41.3</td>
<td>40.4</td>
<td>41.1</td>
<td>39.7</td>
</tr>
<tr>
<td>Cost of CO2 avoided(5) vs. supercritical w/o capture, $/tonne</td>
<td>48.2</td>
<td>40.4</td>
<td>34.8</td>
<td>42.8</td>
</tr>
</tbody>
</table>

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

(1) Efficiency = 3414 Btu/kW-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 @ 11.3%, 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

### PULVERIZED COAL COMBUSTION POWER GENERATION: WITHOUT CO2 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, SOx and NOx. The flue gas exiting the clean-up section meets criteria...
pollutant permit requirements, typically contains 10–15% CO\textsubscript{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\textsubscript{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\textsubscript{x} reductions and greater than about 90% NO\textsubscript{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\textsubscript{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

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**Figure 3.2** Subcritical 500 MW, Pulverized Coal Unit without CO\textsubscript{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<sub>e</sub> 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 CO₂ emissions per MW<sub>e</sub>-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<sub>x</sub> formation.
and SO₂ capture by reaction with CaO to form CaSO₄. 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 SO₂ 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 SO₂ 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-
Coal-based electricity generation 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\textsubscript{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\textsubscript{x} [26] and established emissions reductions guidelines for NO\textsubscript{x}. This has helped produce a 38% reduction in total SO\textsubscript{x} emissions over the last 30 years, while coal-based power generation grew by 90%. Total NO\textsubscript{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\textsubscript{x} emissions and an additional 45% reduction in total NO\textsubscript{x} emissions nationally by 2020. During this period, coal-based generation is projected to grow about 35%. Mercury reduction initially comes with SO\textsubscript{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\textsubscript{x}, and NO\textsubscript{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\textsubscript{x} removal without additives and 99% SO\textsubscript{x} removal with additives [30]. Selective catalytic reduction (SCR), combined with low-NO\textsubscript{x} combustion technology, routinely achieves 90+% NO\textsubscript{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 $/\text{kW}_\text{e}$-h

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

* U.S coal reserves are ~ 48 % anthracite & bituminous, ~37 % subbituminous, and ~ 15 % lignite (See Appendix 3-A, Figure A.2 for more details.)
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, SO₂, and NOₓ 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 ¢/kWe-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.

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

<table>
<thead>
<tr>
<th></th>
<th>CAPITAL COST [$/kWe]</th>
<th>O&amp;M [¢/kWe-h]</th>
<th>COE [¢/kWe-h]</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM Controld</td>
<td>40</td>
<td>0.18</td>
<td>0.26</td>
</tr>
<tr>
<td>NOₓ (50 – 90)*</td>
<td>25 (0.05 – 0.15)</td>
<td>0.15 (0.15 – 0.33)</td>
<td></td>
</tr>
<tr>
<td>SO₂ (100 – 200)+</td>
<td>150 (0.20 – 0.25)</td>
<td>0.52 (0.40 – 0.65)</td>
<td></td>
</tr>
<tr>
<td>Incremental control cost</td>
<td>215</td>
<td>0.50</td>
<td>0.93f</td>
</tr>
</tbody>
</table>

* 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.
* 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.
* Incremental COE impact, bituminous coal
* Particulate control by ESP or fabric filter included in the base unit costs
* Range is for retrofits and depends on coal type, properties, control level and local factors
* When added to the “no-control” COE for SC PC, the total COE is 4.78 ¢/kWe-h

CO₂ 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 CO₂ binding energy are required by the low concentration of CO₂ in the flue gas, and the energy requirements for regeneration are high.

A subcritical PC unit with CO₂ capture (Figure 3.4), that produces 500 MWₚ net power, requires a 37% increase in plant size and in coal feed rate (76,000 kg/h more coal) vs. a
500 MW<sub>e</sub> unit without CO<sub>2</sub> 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<sub>2</sub> capture are illustrated in Figure 3.5. The thermal energy required to recover CO<sub>2</sub> from the amine solution reduces the efficiency by 5 percentage points. The energy required to compress the CO<sub>2</sub> 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<sub>2</sub> capture (Figure 3.6) that produces the same net power output as an ultra-supercritical PC unit without CO<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub> capture, its efficiency is essentially the same as that of the subcritical unit without CO<sub>2</sub> capture.

**COST OF ELECTRICITY FOR AIR-BLOWN PULVERIZED COAL COMBUSTION**

The cost of electricity (COE), without and with CO<sub>2</sub> 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...
the min, max, and mean of the estimated TPC for each technology expressed in 2005 dollars. Costs are for a 500 MW, plant and are given in $/kW{\text{e}}$ 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. Appendix 3.C provides more detail.

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 CO₂ 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 $1730/kWₑ in 2007$. 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 CO₂ capture, the COE decreases from 4.84 to 4.69 ¢/kWₑ-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 CO₂ capture ranges from 3.3 ¢/kWₑ-h for subcritical generation to 2.7 ¢/kWₑ-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 CO₂ 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 kWₑ and with CO₂ capture and recovery. For air-blown PC combustion technologies, the cost of avoided CO₂ 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 CO₂ capture for air-blown PC generation (Figure 3.5 and 3.7) is the energy...
required to regenerate the amine solution (recovering the CO₂), 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 CO₂ avoided cost to about $30 per tonne, a reduction of over 25%.

**RETROFITS FOR CO₂ 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 CO₂ capture is important to the future management of CO₂ 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 CO₂ from the flue gas, and to dry and compress the CO₂ 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 CO₂ 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 CO₂ (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 CO₂ 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 CO₂ capture. Although the total capital cost for this approach is higher, the cost/kWₑ 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 ¢/kWₑ-h (Appendix 3.E). We conclude that rebuilds including CO₂ capture appear more attractive than retrofits, particularly if they upgrade low-efficiency PC units with high-efficiency technology, including CO₂ capture.

CAPTURE-READY A unit can be considered capture-ready if, at some point in the future, it can be retrofitted for CO₂ 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 CO₂ 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 CO₂ 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 CO₂ capture from air-blown PC combustion are due to the need to capture CO₂ 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 CO₂ 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 CO₂ prior to combustion. Each of these approaches has advantages and disadvantages, but each offers opportunities for electricity generation with reduced CO₂-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 Nth 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 CO₂ from PC units involves burning the coal with ~95%
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 CO₂ 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 CO₂ capture.

A block diagram of a 500 MWₜoxy-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 CO₂ capture (Table 3.1). In this design, wet FGD is used prior to recycle to remove 95% of the SOₓ to avoid boiler corrosion problems and high SOₓ 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 CO₂ stream for transport and geological injection are yet to be established.

| 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         |
| **PERFORMANCE**  |                   |                   |                   |
| Heat rate (1), Btu/kWₜ-h | 8,868            | 11,157            | 8,911             | 10,942          |
| Generating efficiency (HHV) | 38.5%            | 30.6%             | 38.4%             | 31.2%           |
| Coal fed, kg/h | 184,894           | 232,628           | 185,376           | 28,155          |
| CO₂ emitted, kg/h | 414,903          | 52,202            | 415,983           | 51,198          |
| CO₂ captured at 90%, kg/h (2) | 0                | 469,817           | 0                | 460,782         |
| CO₂ emitted, g/kWₜ-h (2) | 830              | 109               | 104              | 832             |
| **COSTS**        |                   |                   |                   |
| Total Plant Cost (3), $/kWₜ | 1,330            | 1,900             | 1,430             | 1,890           |
| Inv. Charge, ¢/kWₜ-h @ 15.1% (4) | 2.70             | 3.85              | 2.90              | 3.83            |
| Fuel, ¢/kWₜ-h @ $1.50/MMBtu | 1.33             | 1.67              | 1.33              | 1.64            |
| O&M, ¢/kWₜ-h | 0.75              | 1.45              | 0.90              | 1.05            |
| **COE, ¢/kWₜ-h** |                   |                   |                   |
| CO₂ avoided vs. same technology w/o capture (5), $/tonne | 40.4             | 40.4              | 40.4              | 30.3            |
| Cost of CO₂ avoided vs. supercritical technology w/o capture (5), $/tonne | 40.4             | 40.4              | 30.3              | 24.0            |

**Basis:** 500 MWₜ, plant net output, Illinois # 6 coal (61.2 wt % C, HHV = 25,350 kJ/kg), & 85% capacity factor; for oxy-fuel SC PC CO₂ 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/kWₜ-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 Nth 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
generating efficiency is 30.6% (HHV), which is about 1 percentage point higher than supercritical PC with MEA CO₂ capture. Current design work suggests that the process can be further simplified with SOₓ and NOₓ 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 CO₂ 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, outweigts 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 CO₂ stream for geological injection (sequestration). Our design produces a highly-pure CO₂ 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 CO₂, oxy-fuel PC combustion could gain up to one percentage point in efficiency, and the COE could be reduced by up to 0.4 ¢/kWe-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 MWₜh CO₂-free coal combustion plant for 2008 start-up[43]; Hamilton, Ontario is developing a 24 MWe 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 CO₂ 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).
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¢/kWe·h (Table 3.5). There may be some upside potential in these numbers if supercritical CO₂ stream purity can be relaxed and design efficiencies gained, but more data are needed.

**RETAILS**

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 $/kWₑ basis, is projected to produce electricity at 10% to 15% less than an MEA retrofit, and has a significantly lower CO₂ 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 MWₑ 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 MWₑ) are operating in refineries gasifying asphalt and refinery wastes [51, 52]; a smaller one (180 MWₑ) is operating on petroleum coke. The motivation for pursuing IGCC is the potential for better environmental performance at a lower marginal cost, easier CO₂ 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.
IGCC: WITHOUT CO₂ 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 MWₑ 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.

Table 3.6 Classification and Characteristics of Gasifiers

<table>
<thead>
<tr>
<th>MOVING BED</th>
<th>FLUID BED</th>
<th>ENTRADED FLOW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Outlet temperature</td>
<td>Low (425-600 °C)</td>
<td>High (1250-1600 °C)</td>
</tr>
<tr>
<td>Oxidant demand</td>
<td>Low</td>
<td>Moderate</td>
</tr>
<tr>
<td>Ash conditions</td>
<td>Dry ash or slagging</td>
<td>High</td>
</tr>
<tr>
<td>Size of coal feed</td>
<td>6-50 mm</td>
<td>Dry ash or agglomerating</td>
</tr>
<tr>
<td>Acceptability of fines</td>
<td>Limited</td>
<td>Slagging</td>
</tr>
<tr>
<td>Other characteristics</td>
<td>Methane, tars and oils present in syngas</td>
<td>Low carbon conversion</td>
</tr>
</tbody>
</table>

Figure 3.12 500 MWₑ IGCC Unit without CO₂ Capture
Applying CO₂ capture to IGCC requires three additional process units: shift reactors, an additional CO₂ separation process, and CO₂ compression and drying. In the shift reactors, CO in the syngas is reacted with steam over a catalyst to produce CO₂ and hydrogen. Because the gas stream is at high pressure and has a high CO₂ concentration, a weakly CO₂-binding physical solvent, such as the glymes in Selexol, can be used to separate out the CO₂. Reducing the pressure releases the CO₂ and regenerates the solvent, greatly reducing the energy requirements for CO₂ capture and recovery compared to the MEA system. Higher pressure in the gasifier improves the energy efficiency of both the separation and CO₂ 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 MWₑ IGCC unit designed for CO₂ capture is shown in Figure 3.13. For CO₂ 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 CO₂ capture. Adding CO₂ 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 CO₂ capture is used.

Figure 3.14 illustrates the major impacts on efficiency of adding CO₂ capture to IGCC. CO₂ compression and water gas shift each have

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**BOX 3.1 IGCC DEMONSTRATIONS**

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/kWₑ. The project was eventually abandoned, but it provided the basis for the Tampa Electric Polk Power Station. The DOE supported the 250 MWₑ Polk Station commercial IGCC demonstration unit, using a Texaco gasifier, which started up in 1996. The total plant cost was about $1800/kWₑ. 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 account, 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 82.4% 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 MWₑ capacity, and an efficiency of ~38.4%. Start-up history was similar to that of the Polk unit. LGT provided the basis for Wabash.
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 (~$400/kWe from min to max) in the TPC from the design studies for both no-capture and capture cases as shown in Figure A-3.C.2 (Appendix 3.C). Each estimate is for a 500 MW$_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¢/kWe·h for no capture and 0.9¢/kWe·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/kWe·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¢/kWe·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
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 CO₂ capture, the cost of electricity from IGCC will be from 5 to 11% higher than from supercritical PC. When CO₂ capture is considered, the cost of electricity produced by IGCC will be from 30 to 50% higher than from supercritical PC. 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 kWₑ 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 CO₂ 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 CO₂ 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 ultrasupercritical PC combustion and lower energy consuming CO₂ capture technology, when developed, could have a lower COE than water-slurry fed IGCC with CO₂ 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 ¢/kWₜ-h to 5.00 ¢/kWₜ-h and the COE for IGCC to 5.16 ¢/kWₜ-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 CO₂ 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 CO2 regulations. The introduction of a CO2 tax at a future date (dependent on date of imposition, CO2 tax rate, rate of increase, potential grandfathering and retrofitt 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 CO2 CAPTURE** Retrofitting an IGCC for CO2 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 CO2 capture and recovery, and of CO2 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 CO2 capture is quite different from an optimum unit design for CO2 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 CO2-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 CO2 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 CO2-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. Sparring 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 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<sub>e</sub> 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
synthesis gas today is ammonia. Although most U.S. ammonia plants were designed to produce their syngas by reforming natural gas, worldwide 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.

CITATIONS AND NOTES

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 invariant from 1992 to 2003. NETL (2002) gives coal fleet plant efficiency 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.
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).
9. Of these variables, steam cycle severity (steam temperature and pressure) is the most important. Steam cycle severity increases from subcritical to supercritical to ultracritical. Increasing severity means that the steam carries more available energy to the steam turbine, resulting in higher generating efficiency.


14. Tonne is used to refer to metric or long tonnes, which are 2200 pounds or 1000 kg, and Ton is used to refer to a short ton which is 2000 pounds. Although both are used in this report, we are consistent in distinguishing tonne and ton.

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 liquid 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.


25. NCC, Opportunities to Expedite the Construction of New Coal-Based Power Plants. 2004, National Coal Council.


32. The options for CO2 capture include: (a) chemical absorption into solution, (b) physical adsorption with an adsorbent, (c) membrane separation from the gas, and (d) cryogenic separation, by distillation or freezing. Methods b through d are best suited to high concentrations of CO2 and or gas streams at high pressure, and not the low concentrations of CO2 in flue gas at one atmosphere total pressure.


35. These include EPRI reviews of electricity generating costs, National Coal Council consensus numbers, and generating equipment makers and utilities comments on published numbers.
46. NETL, NETL Coal Power Database, NETL, Editor. 2002, U.S. DOE.
47. Simbeck, D., Existing Power Plants - CO2 Mitigation Costs, Personal communication to J.R. Katzer, 2005: Cambridge, MA.
54. To estimate the COE for IGCC, without and with CO2 capture, we developed a consistent set of TPC numbers from the design studies and then compared these and our cost deltas with industry consensus group numbers to arrive at the TPC numbers given in Table 3.5. We estimated the O&M costs and calculated the COE using the parameters in Table 3.4. These are the COE numbers in Table 3.5.