The Future of Coal-Based Power Generation

(UN Sustainable Development and CCS Meeting)
(September 10-11, 2007)

James R. Katzer*

MIT Energy Initiative

Introduction

This paper is built from the MIT "The Future of Coal" report which can be viewed and downloaded from the MIT website [1]. As we think about the future of coal, we need to embrace the concept that "Times are Changing" and accept the statement attributed to Yogi Berra that "The Future Ain't What It Used To Be". Reflect on that for a minute.

This paper focuses on the technologies for generating electricity from coal; including their cost and performance without CO_2 capture and with CO_2 capture. Because of coal's image of being "Dirty" the paper also addresses criteria emissions performance. It then addresses the transport and sequestration of captured CO_2. When we put all this information together, what does it mean to the future use of coal? And what are some considerations of the Path Forward. The bottom line is "Coal will, by necessity, remain a major component in our electricity generating portfolio for the foreseeable future.

First, we need to define the design bases used for each generating technology in the study.

- Each unit was a Greenfield unit with 500 MW_e net generating capacity
- Each technology was designed to control emissions to below today's best demonstrated performance
- Costs were based on 2000 to 2004 detailed cost designs; indexed to the 2007 construction costs environment. <u>Construction costs represent an update from the values in the published report.</u>

---

* Contact at jrksail@comcast.net

- We integrated existing commercially demonstrated technologies, and cost estimates are for the N[th] plant for those technologies that are still evolving.
- We chose a single set of conditions (Illinois #6 high-sulfur coal, 85 % capacity factor, etc.) for each technology and used EPRI recommended approach to calculate levelized electricity cost (COE). This provides an indicative cost comparison from technology to technology. It is critical to note that coal, site, location, dispatch strategy, and a myriad of design and operating decisions will affect cost.

The important issue here is comparison among technologies without CO_2 capture and with CO_2 capture.

Pulverized Coal (PC) Power Generation.

Without CO_2 Capture: To cover the total topic we move through the generation technologies at a fairly high level. The details are in the report. Schematically, an advanced PC plant can be viewed as shown in Figure 1. The design of the steam cycle block largely determines the generating efficiency of the unit. For PC units, typical

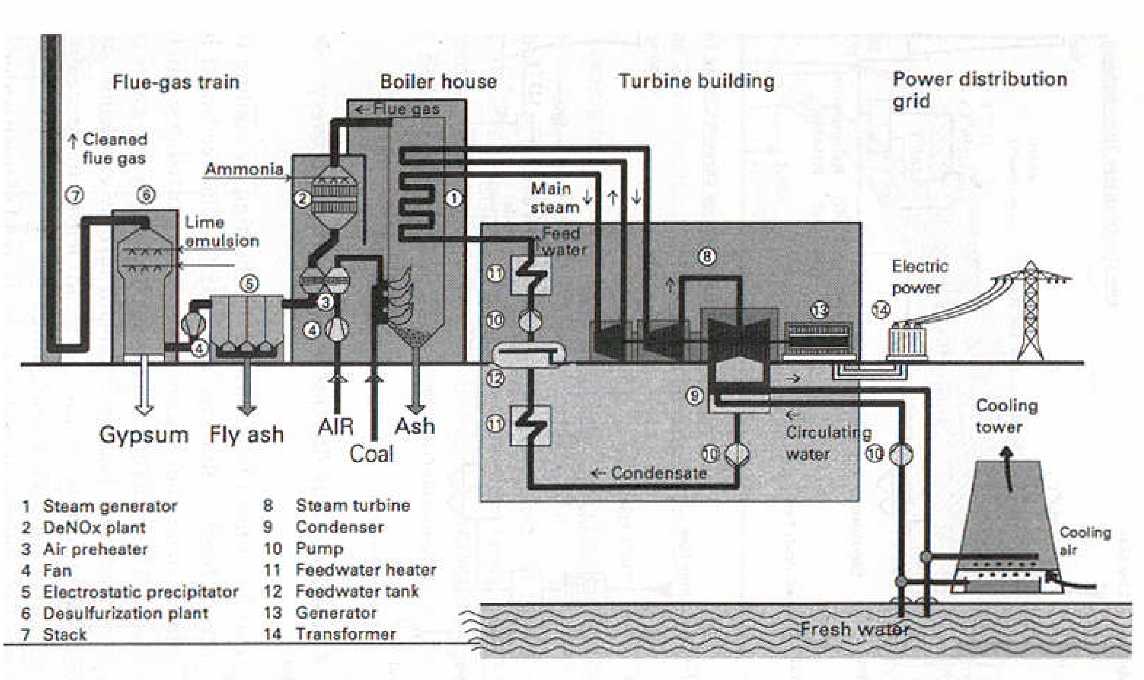

Figure 1. Advanced Pulverized Coal Plant (Courtesy ASME)

operating conditions and overall electrical generating efficiency are:

- Sub-Critical Unit
    - Operation to 1025 ^{o}F and 3200 psi
    - 33 to 37 % efficiency (HHV)
- Supercritical Unit
    - Typical operation 1050 ^{o}F and 3530 psi
    - 37 to 42 % efficiency (HHV)
- Ultra-Supercritical Unit
    - Typical 1110-1140 ^{o}F and 4650 psi
    - 42 to 45 % efficiency (HHV)

The U. S. has built largely subcritical units in the past. A limited number of supercritical units have been built, and interest has recently increased in supercritical technology in the U. S. Europe and Japan have built about a dozen ultra-supercritical units during the last decade [2]. Moving from subcritical to ultra-supercritical generation reduces coal consumption by over 20 % per unit electricity generated. Obviously, the higher the efficiency the lower the CO_2 emissions per unit electricity generated.

At a bare minimum, we need to move to the highest efficiency generation that is economically justified to reduce CO_2 emissions.

<u>With CO_2 Capture:</u> The choice for CO_2 capture today would be amine adsorption. Amine CO_2 capture is commercially proven and would be applied as another process unit at the end of the flue gas train as shown in Figure 2. A large amount of energy is required to recover the CO_2 from the solution, regenerating it to capture more CO_2. A smaller amount of energy is needed to compress the CO_2 to a supercritical fluid. For a supercritical generating unit, the generating efficiency is reduced by about 9 percentage points from say 38 % to 29 %. To maintain constant electrical output requires a 32 % increase in coal consumption. Improvements can be expected, but there are physiochemical and thermodynamic limitations to how large these improvements can be.

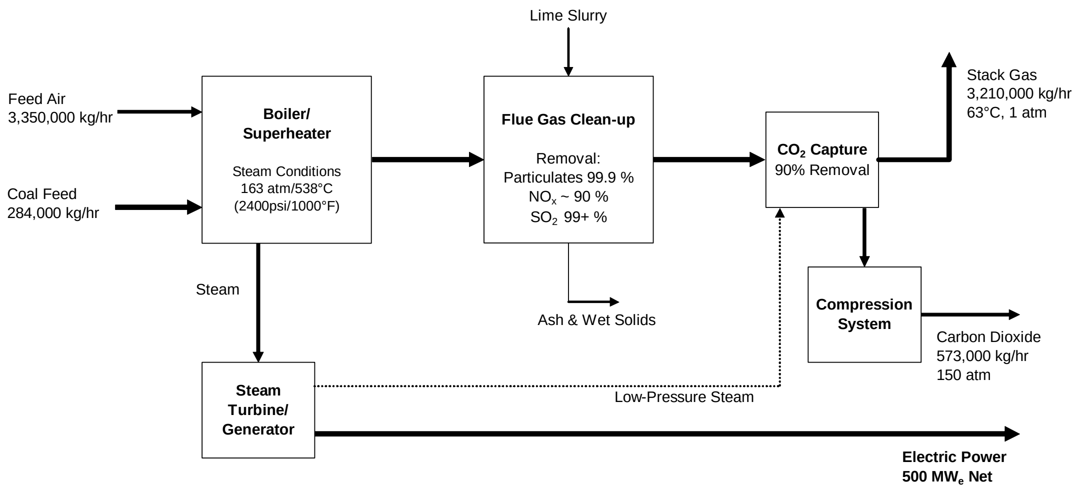

Figure 2. Subcritical 500 MW_e Pulverized Coal Unit with CO_2 Capture

The main problem is the low CO_2 concentration in the flue gas due to nitrogen dilution from air combustion. This can be solved at a cost by substituting oxygen for air. For PC combustion this is oxy-fuel PC combustion. Another approach is to gasify the coal with oxygen and steam, and remove the CO_2 at high pressure. This is IGCC.

Oxy-Fuel PC Combustion

Oxy-fuel combustion, addresses the issue of high capture and recovery costs but does so at the expense of an air-separation unit and its associated energy costs [3, 4]. The advantage is gained through being able to directly compress the flue gas stream, with drying, to produce a supercritical CO_2 stream for sequestration. The technology is in active pilot plant development and the early stages of commercial development. At least two 10 to 25 MW_e commercial demonstrations are moving forward. Because of the early state of commercial development, the performance and cost estimates are not as firm as those for PC or IGCC. Oxy-fuel PC has the potential for lower COE and lower CO_2 avoided cost than with PC capture. It is a technology to watch for further developments.

IGCC

Without CO_2 Capture: The other option is integrated gasification combined cycle (IGCC) generation (see Figure 3). Typically, oxygen is used to combust sufficient carbon in the gasifier at 500 to 1000 psig to increase the temperature to around 1500 ^oF. At this temperature water (steam) reacts with the remaining carbon to convert it to a mixture of carbon monoxide and hydrogen with a range of minor impurities. The gases are cleaned and are then burned in a turbine in a combined cycle power block that is very much like a natural gas combined cycle unit. Because all the gases are contained at high pressure, high levels of, particulate, sulfur and mercury removal are possible. Emissions levels from an IGCC unit should be similar to those from a NGCC unit.

The gasifier is the biggest variable in the system in terms of type (water-slurry feed, dry feed, operating pressure, etc) and the amount of heat removed from it. For electricity generation without CO_2 capture, radiant and convective cooling sections that produce high-pressure steam for power generation lead to efficiencies that can approach or somewhat exceed 40 %.

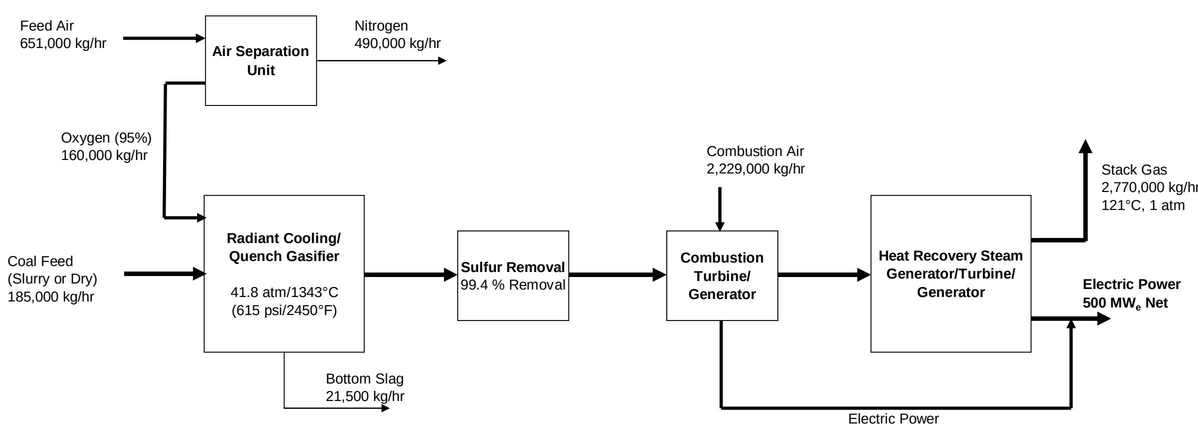

Figure 3. 500 MW_e IGCC Unit Without CO_2 Capture

With CO_2 Capture: To achieve CO_2 capture with IGCC, two shift reactors are added that react carbon monoxide with steam to produce hydrogen and CO_2. (see Figure 4) The gas clean-up process is effectively doubled in size to first remove sulfur and then CO_2. The CO_2 capture and recovery is done at high concentration and pressure and, as such, is cheaper than for CO_2-capture from flue gas capture. All the technologies here are commercial. However, they have yet to be integrated together and demonstrated at the scale of operation here.

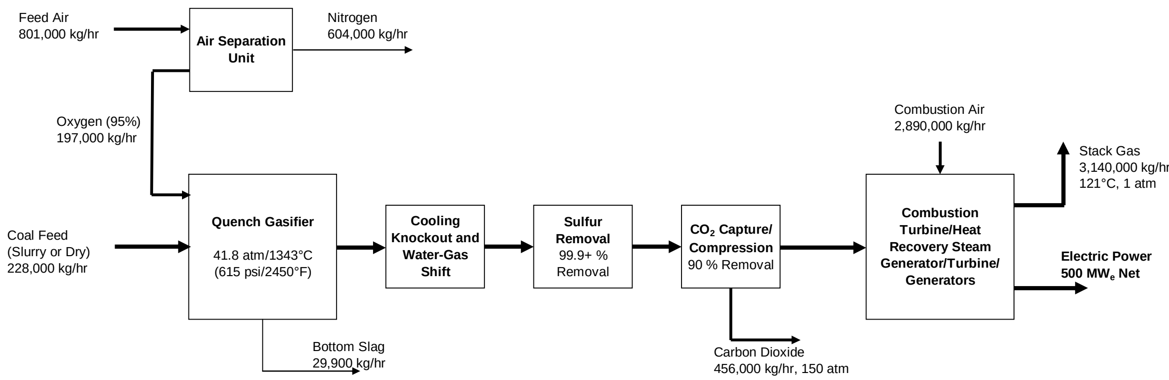

Figure 4. 500 MW_e IGCC With CO_2 Capture

Next, we will look at the component costs and the cost of electricity (COE) (see Table 1).

Table 1. Performance and Costs of Generating Technologies

	Subcritical PC		Supercritical PC		Oxy-Fuel PC	IGCC	
	w/o capture	w/ capture	w/o capture	w/ capture	w/capture	w/o capture	w/capture
PERFORMANCE							
Heat Rate, Btu/kWe-h	9,950	13,600	8,870	11,700	11,200	8,890	10,900
Efficiency (HHV)	34.3%	25.1%	38.5%	29.3%	30.6%	38.4%	31.2%
CO_2 emitted, g/kWe-h	931	127	830	109	104	824	101
COSTS							
Total Plant Cost, $/kWe	$1,580	$2,760	$1,650	$2,650	$2,350	$1,770	$2,340
Cost of Electricity							
Inv. Charge, ¢/kWe-h @ 15.1%	3.20	5.60	3.35	5.37	4.77	3.59	4.75
Fuel, ¢/kWe-h @ $1.50/MMBtu	1.49	2.04	1.33	1.75	1.67	1.33	1.64
O&M, ¢/kWe-h	0.75	1.60	0.75	1.60	1.45	0.90	1.05
COE, ¢/kWe-h	**5.45**	**9.24**	**5.43**	**8.72**	**7.89**	**5.82**	**7.44**
Cost of CO_2 avoided vs. same technology w/o capture, $/tonne		47.1		45.7	34.0		22.3

Basis: 500 MWe plant. Illinois # 6 coal, 85% capacity factor, COE at bus bar. Based on design studies between 2000 and 2004, a period of cost stability, indexed to 2007 $ using construction cost index

Note again that these are indicative costs to allow comparison from technology to technology indexed to 2007 construction costs. Without CO_2 capture, PC has the lowest COE; the COE for IGCC is about 8% higher. However, when we look at the COE with CO_2 capture, IGCC has the lowest COE. The cost of capture and compression for supercritical PC is about 3.3 ¢/kW_e-h; that for IGCC is about one half that or about 1.6 ¢/kW_e-h. The cost of CO_2 avoided for PC is about $46/tonne of CO_2; that for IGCC is about $22/tonne. Oxy-fuel is between these at $34/tonne. These numbers include the cost of capture and compression to a supercritical fluid, but do not include the cost of CO_2 transport and injection. We will look at these latter cost numbers below. This lower COE would appear to make IGCC the technology of choice for CO_2 management in power generation. However as noted above, Oxy-fuel has significant development potential. Further, if we move to a lower rank coal and move up in elevation, the cost difference between IGCC and PC narrows. As such, potentially significant reductions in the capture/recovery cost for PC could make it economically competitive with IGCC with capture in certain applications. IGCC still has concerns about operability and availability associated with it in the power industry. Thus, we cannot close the door on any of these technologies at this point.

"Dirty Coal"

Coal has the reputation of being dirty, largely based in emissions issues. Table 2 gives the commercially demonstrated and projected emissions performance of PC and IGCC [2, 5]. ESP or bag houses are employed on all PC units, and PM emissions are typically very low. Improved ESP or wet ESP can reduce this further, but at a cost. FGD is applied on only about 1/3 of U.S. capacity and thus typical emissions are quite high. The best commercial performance gives the levels of emissions reductions that have been demonstrated in full-scale commercially operating units. Further reductions are possible. In fact with CO_2 capture, emissions levels are expected to be even further reduced [6]. The best commercial performance levels with IGCC are 3- to 10- fold lower.
IGCC with CO_2 capture should have even lower emissions. Although this does not address the whole life-cycle for coal, coal use in the electricity generation step can in fact be very clean.

Table 2. Commercially Demonstrated and Projected Emissions Performance of PC and IGCC Power Generation

Technology	Case	Particulates	SO_2	NO_x	Mercury
		lb/MM Btu	lb/MM Btu	lb/MM Btu	% removed
PC Plant					
	Typical U.S.	0.02	0.25	0.12	
	Best Commercial	0.015 (99.5%)	0.04 (99+%)	0.03	90
	Design w CO_2 Cap.	0.01 (99.5+%)	0.0006 (99.99%)	0.03	75-85
IGCC Plant					
	Best Commercial	0.001	0.015 (99.8%)	0.01	95
	Design w CO_2 Cap.	0.001	0.005 (99.9%)	0.01	>95

The estimated cost to accomplish emissions reductions somewhat below the best demonstrated commercial performance today is shown here and is about 1 ¢/kW_e-h out of about 5.5 ¢/kW_e-h or about 20 %. CO_2 capture and recovery will cost somewhat more than this, based on our understanding of today's technology. Cost reductions can be expected when this technically begins to be commercially practiced.

CCS Life Cycle

The entire life cycle of Carbon Capture and Sequestration (CCS) shown in Figure 5. We will now focus on the last two boxes in the figure: pipeline transport and injection. Here again we will look at the impact on the COE. Before we can do that however we need to have a model of what a typical CCS project would look like. Although oil and gas reservoirs and enhanced oil recovery are often talked about, these storage sites of opportunity have limited long-term potential on the scale of CO_2 CCS that will be needed to make a major difference. Larger volume, long-term storage will probably be in deep saline aquifers. These underlie large portions of the U. S., particularly those areas that today have a lot of coal-based power generation and where additional capacity is expected to be added.

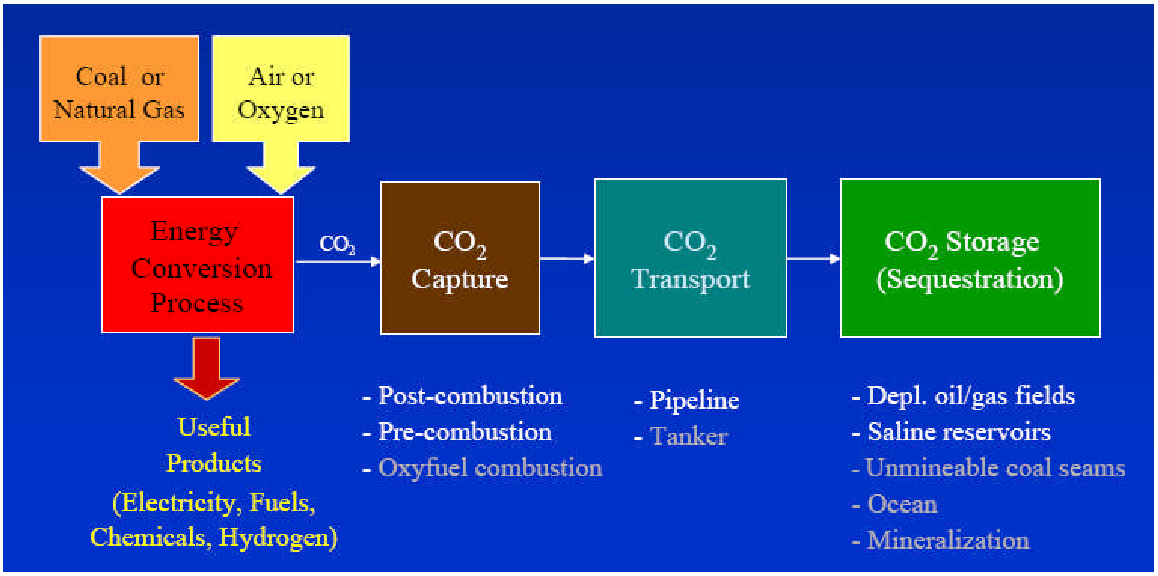

Figure 5. Full Life-Cycle of Carbon Capture and Sequestration

The primary mode of CO_2 transport for sequestration operations will be via pipelines. There are over 2500 km of CO_2 pipeline in the U.S. today, with a capacity in excess of 40 $MtCO_2$/yr. These pipelines were developed to support Enhanced Oil Recovery (EOR) operations, primarily in west Texas and Wyoming. In these pipelines, CO_2 is transported as a dense, single phase at ambient temperatures and supercritical pressures. To avoid corrosion and hydrate formation, water levels are typically kept below 50 ppm.

However, rather than having long-distance CO_2 pipelines running across the country, a typical CCS power plant project could be expected to look something like the illustration in Figure 6. It is expected that sufficient capacity would be accessible within about a 100 km radius for a good location. Location is important, but once sited, the CO_2 storage requirement for the lifetime of the power plant, which would be of order a billion barrels of liquid $CO_{2,}$ should be within the area

Pipeline transport costs are highly non-linear with the amount of CO_2 transported. These economies of scale make transportation costs for large capture projects much less expensive. For example, for 6 million tonnes of CO_2 per year the estimated transport cost is about $1.00 per tonne per 100 km; at 30 million tonnes of CO_2 per year the cost is about \$0.25 per tonne per 100 km [7]. Although these are typical values, costs can be highly

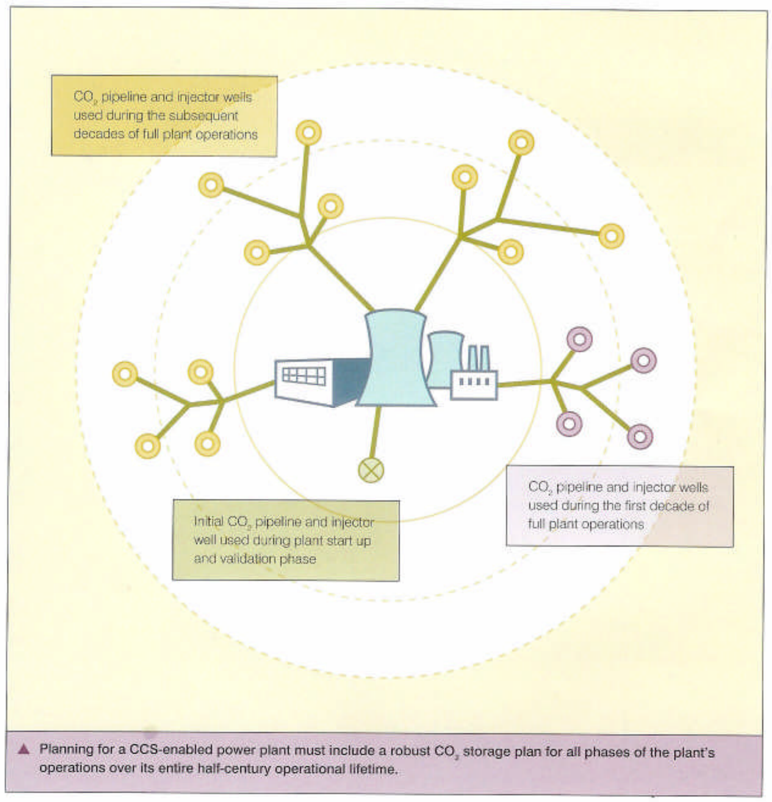

Figure 6. Conceptual Model of a Typical CCS Project

variable from project to project due to both physical (e.g., terrain pipeline must traverse) and political considerations. For a 1 GW_e coal-fired power plant, pipeline capacity of about 6-7 million tonnes of CO_2/yr would be needed. This would result in a transport cost of about \$1.00 per tonne of CO_2 per 100 km.

The major cost for injection and storage is associated with drilling the wells. Other significant costs include site selection and characterization, as well as flowlines and connectors required for injection. In general, no additional pressurization of the CO_2 is required for injection because of the high pressure in the pipeline and the pressure gain due to the gravity head of the CO_2 in the wellbore. Monitoring costs are expected to be small, of order \$0.1 to \$0.3 per tonne of CO_2 [7].

Costs for injecting the CO_2 into geologic formations will vary on the formation type and its properties. For example, costs increase as reservoir depth increases and as reservoir injectivity decreases. Lower injectivity requires drilling of more wells for a given rate of CO_2 injection. A range of typical injection costs has been reported as \$0.5 to \$8 per tonne of CO_2 [7]. Combining storage with Enhanced Oil Recovery (EOR) can help offset some of the capture and storage costs. EOR credits of up to \$20 per tonne of CO_2 may be obtained.

These projected costs, on a levelized basis per kW_e-h, are shown in Table 3.
The costs for transport and injection are significant but both are small and do not represent a potential economic show-stopper. Comprehensive geological reviews suggest that there appear to be no technical show-stoppers for CO_2 injection and storage either. However, there are technical issues that require resolution. Transport and injection costs include the cost of constructing the pipelines needed and of drilling the needed injection wells, as well as the operating costs. The numbers used here are on the high end of the current ranges cited above. The largest cost is in capture and compression. For IGCC the projected cost of CCS would increase the bus bar cost of electricity by about 50 %, from 5.8 to about 8.2 ¢/kW_e-h. This electricity would be very low emissions electricity, including low CO_2 emissions. Furthermore, it is economically competitive with electricity from wind power and nuclear power.

Table 3. Costs of CCS Projected for PC and IGCC Generation with Capture

Technology	PC		IGCC
CCS Step	¢/kW_e-h		¢/kW_e-h
Capture	2.7		1.21
Compression	0.6		0.4
Transport	0.19		0.18
Injection	0.68		0.64
Totals	4		2.4

Were does all this lead us. There are three key points to stress:

1. First, about 50% of our coal reserves are bituminous coal and 50% are subbituminous coal and lignite. When we move to these lower rank coals and move to higher elevations, the gap between IGCC with capture and PC with capture narrows. Cost improvements for PC capture could make it economically competitive with IGCC in certain applications. At the same time, Oxy-fuel PC looks potentially competitive also. Thus, It is too early to pick winners for coal-based power generation with CO_2 capture.
2. Second, emissions from coal-based power generation can be very low; and with CO_2 capture, emissions can be even lower; to the extent of being very clean and with very low CO_2 emissions as well.
3. Third, with CO_2 capture and sequestration, coal can provide electricity that is cost competitive with wind and nuclear.

Thus, coal would appear to continue to be an economic choice for base-load generation of very low emissions electricity , including low CO_2 emissions.

Finally, what are the issues with respect to the path forward?

- The technoloies for CO_2 capture with generation are all commercial. Although they have typically not been applied at the scale of interest here, they can be expected to improve in cost and performance from operation at scale. We do not need major R&D breakthroughs to begin applying them.

- Current information indicates that it is technically feasible to safely and effectively store large quantities of CO_2 in saline aquifers, and the storage capacity appears very large. Some technical issues need resolution.
- A broad range of regulatory issues require resolution. These include: permitting guidelines and procedures, liability and ownership, monitoring and certification, site closure, remediation, etc.
- For CCS to be available to apply on a large scale it is critical to gain political and public confidence of the safety and efficacy of geologic sequestration.

To resolve the issues outlined above and quickly establish CCS as a viable technology for managing CO_2 emissions, it is necessary to establish 3 to 5 large-scale CCS demonstration projects in the U.S. at 1 million tonnes CO_2 per year, using different generation technologies, focusing on different geologies, and operated for several years. This if completed expeditiously, can provide the U. S. with technical options for addressing CO_2 emissions.

The central message of the MIT study is that demonstration of technical, economic, and institutional features of carbon capture and sequestration at commercial scale coal combustion and conversion plants, will: (1) give policymakers and the public confidence that a practical carbon mitigation control option exists, (2) shorten the deployment time and reduce the cost for carbon capture and sequestration should a carbon emission control policy be adopted, and (3) maintain opportunities for the lowest cost and most widely available energy form to be used to meet the world's pressing energy needs in an environmentally acceptable manner.

Citations and Notes

1. **MIT.** ***The Future of Coal; Options in a Carbon-Constrained World*. 2007 March, 2007 [cited; Available from: http://web.mit.edu/coal/.**
2. **PowerClean, T.N., *Fossil Fuel Power Generation State-of-the-Art*, P.T. Network, Editor. 2004, University of Ulster: Coleraine, UK. p. 9-10.**
3. **Dillon, D.J., R. S. Panesar, R. A. Wall, R. J. Allam, V. White, J. Gibbins, and M. R. Haines, *Oxy-combustion Processes for CO2 Capture from Advanced Supercritical PF and NGCC Power Plant*, in *Greenhouse Gas Technologies Conference 7*. 2004: Vancouver, BC.**
4. **Jordal, K. and e. al, *Oxyfuel Combustion of Coal-Fired Power Gerneration with CO2 Capture -- Opportunities and Challenges.* XDQ, 2004.**
5. **USEPA, *Continuous Emissions Monitoring System (CEMS) Data Base of 2005 Power Plant Emissions Data*. 2005, EPA.**
6. **Holt, N., *Preliminary Economics of SCPC & IGCC with CO_2 Capture and Storage*, in *2nd IGCC and Xtl Conference*. 2007: Freiberg, Germany.**
7. **IPCC, ed. *IPCC Special Report on Carbon Dioxide Capture and Storage*. ed. B.e.a. Metz. 2005, Cambridge University: Cambridge.**