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Energy Policy 35 (2007) 4444–4454

ENERGY POLICY

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Cost and performance of fossil fuel power plants with CO_2 capture and storage

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Received 13 January 2007; accepted 7 March 2007
Available online 26 April 2007

Abstract

CO_2 capture and storage (CCS) is receiving considerable attention as a potential greenhouse gas (GHG) mitigation option for fossil fuel power plants. Cost and performance estimates for CCS are critical factors in energy and policy analysis. CCS cost studies necessarily employ a host of technical and economic assumptions that can dramatically affect results. Thus, particular studies often are of limited value to analysts, researchers, and industry personnel seeking results for alternative cases. In this paper, we use a generalized modeling tool to estimate and compare the emissions, efficiency, resource requirements and current costs of fossil fuel power plants with CCS on a systematic basis. This plant-level analysis explores a broader range of key assumptions than found in recent studies we reviewed for three major plant types: pulverized coal (PC) plants, natural gas combined cycle (NGCC) plants, and integrated gasification combined cycle (IGCC) systems using coal. In particular, we examine the effects of recent increases in capital costs and natural gas prices, as well as effects of differential plant utilization rates, IGCC financing and operating assumptions, variations in plant size, and differences in fuel quality, including bituminous, sub-bituminous and lignite coals. Our results show higher power plant and CCS costs than prior studies as a consequence of recent escalations in capital and operating costs. The broader range of cases also reveals differences not previously reported in the relative costs of PC, NGCC and IGCC plants with and without CCS. While CCS can significantly reduce power plant emissions of CO_2 (typically by 85–90%), the impacts of CCS energy requirements on plant-level resource requirements and multi-media environmental emissions also are found to be significant, with increases of approximately 15–30% for current CCS systems. To characterize such impacts, an alternative definition of the "energy penalty" is proposed in lieu of the prevailing use of this term.

Keywords: CO_2 capture and storage cost; Comparative power plant economics; Carbon sequestration energy requirements

1. Introduction

CO_2 capture and storage (CCS) is receiving considerable attention as a potential greenhouse gas (GHG) mitigation option that could allow a smoother and less costly transition to a sustainable, low-carbon energy future over the next century (Riahi et al., 2003; IPCC, 2005). Although commercial technology exists to separate and capture the CO_2 generated in large-scale industrial processes, applications to date are found mainly in the petroleum and petrochemical industries (such as for natural gas processing and ammonia production). Capture of CO_2 from combustion-generated flue gases also has been demonstrated commercially at small scale for gas-fired and coal-fired boilers (Rao and Rubin, 2002). However, to date there have been no applications of CO_2 capture at an electric power plant at a large scale (e.g., 100 MW or more). Geological sequestration of captured CO_2 also has been demonstrated at three large-scale projects in Norway, Canada and Algeria (each storing over one million tons CO_2 per year), with other smaller-scale projects planned or underway worldwide (IPCC, 2005). Nevertheless, the legal and regulatory frameworks for a geological CO_2 sequestration program as a GHG abatement method largely remain to be developed.

The cost of CCS technology could pose another barrier to its widespread use as a GHG control strategy. The total cost of CCS includes the cost of CO_2 capture and compression; the cost of CO_2 transport (typically via a

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0301-4215/$ - see front matter
doi:10.1016/j.enpol.2007.03.009

pipeline); and the cost of CO_2 storage (in this study, limited to geological sequestration, although other methods also are under investigation). A number of recent studies have estimated CCS costs based on technologies that are either currently commercial or under development (IPCC, 2005). Relatively few studies are published in peer-reviewed journals. For the most part, they focus on coal-based power plants, which are a major source of CO_2 emissions. Most studies consider only CO_2 capture costs and do not include the costs of transport and storage. While some studies also have reported ancillary benefits of CO_2 capture, such as improved capture of criteria air pollutants (like sulfur dioxide, SO_2), a more complete picture of the environmental and resource implications of CO_2 capture is largely lacking in the current literature.

1.1. Scope and objectives of this paper

Our principal objectives in this paper are to: (1) summarize and compare the results of recent studies of the current cost of fossil fuel power systems with and without CO_2 capture, including pulverized coal (PC) combustion plants, coal-based integrated gasification combined cycle (IGCC) plants, and natural gas combined cycle (NGCC) plants; (2) explore a broader range of key assumptions that influence these cost comparisons; and (3) quantify the implications of CCS energy requirements on plant-level resource requirements and multi-media emissions. The latter topic has not received attention in most studies of CCS options, but its consequences are potentially significant, as the analysis below will demonstrate. We conclude by discussing the potential for advanced technologies to reduce the costs and ancillary impacts of CCS applied to power generation technologies.

2. Review of recent cost studies

Table 1 summarizes the range of costs reported for different power generation systems in recent studies we reviewed in conjunction with a Special Report by the Intergovernmental Panel on Climate Change (IPCC, 2005). These costs are for new power plants using current commercial power generation and CO_2 capture technologies. They include the cost of CO_2 compression, but not CO_2 transport and storage costs, which are outside the scope of most recent studies.

Table 1 reveals substantial variability in both the absolute and relative costs of power generation and CO_2 capture for the three fossil fuel systems shown. This arises mainly from different assumptions about key factors that affect the projected cost of electricity (COE) for a particular system (such as fuel properties, fuel cost, plant size, plant efficiency, plant capacity factor, and plant financing), as well as assumptions about the performance and operation of the CO_2 capture unit and other emission control systems. A study by Rao and Rubin (2002) illustrated the contribution of different factors to the overall cost of a PC plant with CCS. Table 1 reflects an even broader range of assumptions and perspectives for each of the three power systems.

The general conclusion that emerges from studies published prior to 2004 is that the total COE generation tends to be lowest for NGCC plants, with or without CO_2 capture. For coal-based plants, PC units tend to have lower capital costs and lower COE without capture, while IGCC plants tend to be less expensive when current CO_2 capture systems are added. However, since costs depend on many factors, the generalizations above do not apply in all cases. In particular, as elaborated below, most recent studies of NGCC systems are based on fuel price and other assumptions that today appear highly questionable. In recent years, the price of natural gas, as well as many raw materials has escalated considerably, leading to cost increases that are not reflected in the current literature. Thus, we seek in this paper to update prior cost estimates, and to explore systematically a broader range of conditions that affect the comparative costs of fossil fuel power plants with and without CCS.

3. Analytical method for comparative assessments

To account for the many factors that affect CCS costs and emissions at electric power plants, we use the Integrated Environmental Control Model (IECM) to systematically evaluate the three types of fossil fuel power systems noted above. The IECM is a publicly available and widely used modeling tool developed by Carnegie Mellon University for the US Department of Energy's National Energy Technology Laboratory (DOE/NETL) (IECM, 2006). It has been employed previously to characterize the costs of PC plants using an amine-based CO_2 capture system (Rao and Rubin, 2002). More recently, the IECM has been updated and expanded to include NGCC and IGCC plants with and without CCS. As with the PC plant, the NGCC and IGCC models employ fundamental mass and energy balances, together with empirical data, to quantify overall plant performance, resource requirements and emissions. Plant and process performance models are linked to a companion set of engineering-economic and financial models that calculate the capital cost and annual operating and maintenance (O&M) costs of individual plant components, plus the total COE for the overall plant. Cost and performance models in the IECM draw upon a variety of detailed engineering-economic studies, resulting in a generalized modeling tool whose results are consistent with other detailed studies for the same set of input assumptions. Technical documentation for each of the IECM power systems and component models is available elsewhere (IECM, 2006; Rao et al., 2004; Rubin et al., 2003; Frey and Rubin, 1990).

In this paper we focus on some of the major factors that affect the relative costs and environmental impacts of CCS for the three power systems of interest. We employ IECM Version 5.1.2 with all costs updated to 2005 values.

Table 1
Summary of reported CO_2 emissions and costs for a new electric power plant with and without CO_2 capture based on current technology (excluding CO_2 transport and storage costs)

Performance and cost measures	NGCC plant		PC plant		IGCC plant	
	Range	Rep. value	Range	Rep. value	Range	Rep. value
Emission factor without capture (kg CO_2/MWh)	344–379	367	736–811	762	682–846	773
Emission factor with capture (kg CO_2/MWh)	40–66	52	92–145	112	65–152	108
Percentage net CO_2 reduction per kWh (%)	83–88	86	81–88	85	81–91	86
Total capital requirement without capture (US$/kW)	515–724	568	1161–1486	1286	1169–1565	1326
Total capital requirement with capture (US$/kW)	909–1261	998	1894–2578	2096	1414–2270	1825
Percentage increase in capital cost with capture (%)	64–100	76	44–74	63	19–66	37
COE without capture (US$/MWh)	31–50	37	43–52	46	41–61	47
COE with capture only (US$/MWh)	43–72	54	62–86	73	54–79	62
Increase in COE with capture (US$/MWh)	12–24	17	18–34	27	9–22	16
Percentage increase in COE with capture (%)	37–69	46	42–66	57	20–55	33
Cost of net CO_2 captured (US$/t$CO_2$)[a]	37–74	53	29–51	41	13–37	23

All costs in constant US$2002 (IPCC, 2005).
Notes: NGCC = natural gas combined cycle; PC = pulverized coal; IGCC = integrated gasification combined cycle. Rep. Value = representative value based on the average of values in the different studies reviewed (IEA GHG, 2000; IEA GHG, 2003; IEA GHG, 2004; NETL, 2002; Nsakala et al., 2003; Parsons Infrastructure Technology Group and Inc., 2002; Rao and Rubin, 2002; Rubin et al., 2005; Simbeck, 2002; Stobbs and Clark, 2005); COE = cost of electricity production; MWh = megawatt-hours. All PC and IGCC data are for bituminous coals only at costs of 1.0–1.5US$/GJ (LHV); All PC plants are supercritical units; NGCC data based on natural gas prices of 2.8–4.4US$/GJ (LHV basis); Power plant sizes range from approximately 400–800 MW without capture and 300–700 MW with capture; Capacity factors vary from 65% to 85% for coal plants and 50–95% for gas plants (average for each = 80%); Fixed charge factors vary from 11% to 16%.
[a]Cost of net CO_2 captured is equivalent to cost of CO_2 avoided for zero transport and storage cost based on the given plant type with and without capture.

4. Baseline comparisons

We first compare systems based on assumptions similar to those found in other recent studies, except that for the NGCC plant we use a higher natural gas price (of $6/GJ) as our base case. Table 2 summarizes other key assumptions for this baseline analysis. In each case, the "reference plant" is a nominal 500 MW baseload facility without CO_2 capture, while the "capture plant" refers to a similar facility with CCS. All coal-based plants are assumed to use an eastern US bituminous coal commonly used in studies by EPRI and others (O'Keefe and Griffiths, 2000). The PC plant is a modern supercritical unit, whose gross size with capture is adjusted to maintain a net plant output of approximately 500 MW (in contrast to most studies, which assume the reference plant is derated, yielding a lower net output). The IGCC plant is based on a slurry-fed gasifier with a water quench, similar to the GE (formerly Texaco) gasifier, which is the gasifier used most extensively worldwide. The NGCC and IGCC plants with capture both retain the same gas turbine equipment as their respective reference plants since gas turbines are available only in discrete sizes. However, other "upstream" components of the IGCC system are larger in size to accommodate the higher coal flow rate needed when CCS is added. Both the PC and NGCC plants employ an amine-based system for post-combustion CO_2 capture, while the IGCC plant adds a water gas shift reactor and a Selexol unit to capture CO_2. All three systems include pipeline transport and geological storage of high-pressure (liquefied) CO_2. The nominal case is injection of CO_2 into a deep saline aquifer, while an alternative case assumes CO_2 is first used for enhanced oil recovery (EOR), thus generating revenue for the CCS system. Key cost assumptions are shown in Table 2. Although the IECM has a probabilistic capability for modeling uncertainty or variability, in this paper we use conventional deterministic analysis for simplicity and ease of comparison with other studies.

Table 3 summarizes the major results of this analysis. The two coal-based reference plants have similar CO_2 emission rates, while the reference NGCC plant emits 55% less CO_2 per MWh. Without CO_2 capture, the PC plant has the lowest levelized COE at $53.0/MWh, while the NGCC plant is highest at $60.3/MWh. This result contrasts with the recent studies in Table 1, which showed NGCC to be lowest-cost system based on lower natural gas prices of approximately $2–4/GJ (vs. $6/GJ here). The 2005 capital costs in Table 3 are roughly 20% higher than comparable 2002 costs reported in recent studies (Table 1). This reflects significant increases in plant construction costs in recent years (CEPCI, 2006).

With CO_2 capture, all three plants remove 90% of the flue gas (or fuel gas) CO_2, but emissions rates per MWh are reduced by only 87–88% because of the CCS energy requirements. Table 3 shows the COE of each system for three cases: first, excluding the cost of transport and storage (as in Table 1), then, two additional cases reflecting the cost of pipeline transport and storage in either a deep saline aquifer or a depleted oil reservoir (with credits for EOR). The cost of CO_2 transport and storage adds 4–10% to the total COE for cases with aquifer storage, and reduces the COE by 7–18% for cases with EOR storage.

Table 2
Key assumptions for the baseline analysis

Parameter	PC[a]		IGCC[b]		NGCC[c]	
	Reference	Capture	Reference	Capture	Reference	Capture
Fuel used	US bituminous coal[d]		US bituminous coal[d]		Natural gas[e]	
Gross plant size (MW)	575	710	615	596	517	517
Net plant output (MW)	528	493	538	493	507	432
Net plant efficiency, HHV (%)	39.3	29.9	37.2	32.2	50.2	42.8
Capacity factor (%)	75	75	75	75	75	75
Fixed charge factor (%)	14.8	14.8	14.8	14.8	14.8	14.8
Fuel price ($/GJ, HHV)	1.2	1.2	1.2	1.2	6.0	6.0
CO_2 capture system		Amine		Shift + Selexol		Amine
CO_2 capture efficiency (%)		90		90		90
CO_2 transport cost ($/tonne CO_2)[f]		3.1		3.1		3.1
Geologic storage cost ($/tonne CO_2)		5.0		5.0		5.0
EOR storage credit ($/tonne CO_2)		15.0		15.0		15.0

[a]Supercritical boiler unit; environmental controls include SCR, ESP and FGD systems, followed by MEA system for CO_2 capture; SO_2 removal efficiency is 98% for reference plant and 99% for capture plant.
[b]Based on GE quench gasifier (2 + 1 spare), 2 GE 7FA gas turbine, 3-pressure reheat HRSG with steam parameters 1400 psig/1000 F/1000 F. Sulfur removal efficiency is 98% via hydrolyzer + Selexol system; Sulfur recovery via Claus plant and Beavon-Stretford tailgas unit.
[c]NGCC plant uses two GE 7FA gas turbines and 3-pressure reheat HRSG.
[d]As-fired properties are: 2.1%S, 7.2% ash, 5.1% moisture and 30.8 MJ/kg HHV.
[e]HHV = 53.9 MJ/kg.
[f]Based on pipeline transport distance of 161 km (100 miles); CO_2 stream compressed to 13.7 MPa (2000 psig) with no booster compressors.

Table 3
Results for the baseline cases using the IECM

Parameter	PC		IGCC		NGCC	
	Reference	Capture	Reference	Capture	Reference	Capture
CO_2 emission rate (kg/MWh)	811	107	822	97	367	43
CO_2 captured (kg/MWh)		959		850		387
CCS plant derating (% output loss)		23.9		13.4		14.7
CCS energy penalty (% fuel input/kWh)		31.4		15.5		17.3
Total capital requirement ($/kW)	1442	2345	1567	2076	671	1091
Cost of electricity[a] ($/MWh)	53.0	88.0	55.5	71.9	60.3	80.6
Cost of CO_2 avoided[a,b] ($/tonne CO_2)		49.7		22.6		62.6
Assuming saline aquifer storage						
Cost of electricity ($/MWh)	53.0	95.9	55.5	79.0	60.3	83.8
Cost of CO_2 avoided[b] ($/tonne CO_2)		60.9		32.4		72.4
Assuming EOR storage						
Cost of electricity ($/MWh)	53.0	73.5	55.5	58.8	60.3	74.7
Cost of CO_2 avoided[b] ($/tonne CO_2)		29.0		4.5		44.4

All costs in constant $US2005.
[a]Levelized cost excluding cost of CO_2 transport and storage.
[b]All avoided cost values are relative to the reference plant for the same system.

With CCS, the IGCC plant is the lowest-cost system in all cases. With aquifer storage the PC plant has the highest COE, while for EOR the NGCC plant (with less CO_2 to sell) has the highest COE. These results indicate that the omission of transport and storage costs (as in most studies to date) can lead to incorrect conclusions about the relative total cost of different power systems. Table 3 shows that the cost of CO_2 avoided ($/tonne CO_2) also is highest for the NGCC plant and lowest for the IGCC plant in all cases. This is consistent with prior studies based on an avoidance cost for the same plant type with and without CCS, defined as the difference in COE divided by the difference in CO_2 emitted per MWh.[1]

5. Effects of gas price and plant dispatch

Two assumptions that are especially important in cost comparisons involving NGCC plants are the natural gas

[1]Other choices of a reference plant can give markedly different results for the cost of CO_2 avoided with CCS. The definition used here is used most commonly in studies of individual power plants.

price and the plant utilization factor. Studies of NGCC plants prior to 2004 typically assumed natural gas prices of approximately \$2–3/GJ over the life of the plant. This reflected the prevailing prices and outlook of the late 1990s and early 2000s, when NGCC was the least-cost plant type in many parts of the world. Consistent with this outlook for gas prices was the assumption of a high annual load factor (capacity factor) for NGCC units, typically 80–90% for the most of the studies reflected in Table 1.

In the US, the low COEs anticipated for NGCC plants led to significant investments in both simple and combined cycle gas plants over the past decade. However, much of that new gas-fired capacity now goes unutilized. As gas prices increased dramatically in recent years, average utilization rates for gas turbine-based plants in the US fell to below 30% (see Fig. 1). These low capacity factors reflect the fact that power plant dispatch is based on the variable operating cost (VOC) of a unit (primarily its fuel cost), not on its total cost of generation (which includes capital costs). Thus, as natural gas prices increased, NGCC plants have been utilized less extensively where coal plants, having lower VOC, were also available.

This coupling between fuel price and plant capacity factor is typically ignored in conventional plant-level cost analyses. A rigorous treatment requires that plant utilization factors be evaluated in the context of a network of generating plants meeting a specified (time-dependent) electricity demand. This type of analysis requires a power plant dispatch model together with models and assumptions regarding power demand, generation mix, transmission constraints, fuel supplies, capacity additions over time, and other constraints (such as a limit or tax on carbon or air pollutant emissions). Recent work by Johnson and Keith (2004) illustrates this approach, which results in different utilization rates for different plant types, depending on the carbon constraint and other factors.

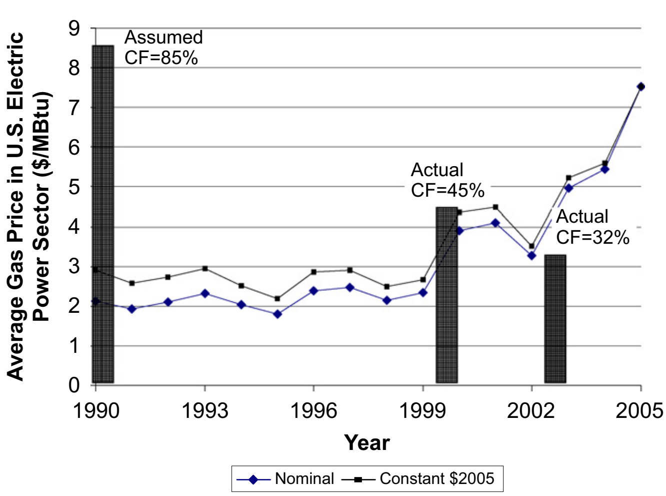

Fig. 1. Recent trend in average price of natural gas for US electric utilities. Vertical bars show typical capacity factor assumption for NGCC-CCS cost analyses and recent actual values for US plants. (EIA, 2006; Rosenberg et al., 2004).

Table 4
Differences in total variable operating cost (VOC) relative to the PC plant[a] (\$2005/MWh)

Plant	Fuel price	Reference	Capture
PC	\$1.2/GJ	(Base case)	(Base case)
IGCC	\$1.2/GJ	~0	−12
NGCC	\$2.2/GJ	2	−9
NGCC	\$4.0/GJ	15	6
NGCC	\$6.0/GJ	29	23
NGCC	\$8.0/GJ	44	39

[a]VOC for the PC plants are \$13.1/MWh for the reference plant and \$30.0/MWh for the capture plant. VOC includes cost of fuel, chemicals, utilities, waste disposal and byproduct credits. Values for the capture plant include the costs of CO_2 transport and storage.

To explore comparative CCS costs in the absence of a particular regional dispatch scenario, we use the differential VOC data in Table 4 to argue qualitatively that the common assumption of a constant (baseload) capacity factor for all types of power plants is not likely to be realistic when comparing CO_2 capture costs for NGCC and coal-based plants. Rather, the data in Table 4 suggest that for the reference case with no CO_2 capture (and no carbon constraint), PC and IGCC plants (if built) would have similar VOCs, and therefore similar utilization rates, as previously assumed. The nominal value of 75% reflects the average capacity factor of modern PC plants currently operating in the United States (Chen, 2005). NGCC units, however, would have decreasing capacity factors as gas prices increase. For illustrative purposes we assume a 50% capacity factor for the NGCC plant. For the capture plants, IGCC units, having the lowest VOC, would be utilized more than PC plants with capture, while NGCC plants with capture, having the highest VOC, would be utilized least.[2] Again for illustrative purposes, we assume capacity factors of 85%, 75% and 50% for the IGCC, PC and NGCC capture plants, respectively. The resulting COEs are shown in Fig. 2. Compared to the earlier (Table 3) results based on equal capacity factors for all three plants, the IGCC plant with CCS now has nearly the same COE as the NGCC plant without capture. For the case with EOR credit, the IGCC-CCS plant has a lower COE than the PC plant without capture. Because of its higher fuel price and low capacity factor, NGCC is again the most expensive system in all scenarios.

6. Effects of IGCC financing and operation

Consistent with other studies, the analysis above suggests that IGCC plants could be an attractive option for electric power generation if CCS technology were

[2]A sufficiently high carbon tax would change this result. For the plants shown here, a tax on CO_2 emissions of \$650/tonne CO_2 (\$2380/tonne C) would be required to equalize the VOC for the IGCC and NGCC capture plants at a natural gas price of \$6.0/GJ. Such values far exceed those typically considered in the literature on power plant GHG controls.

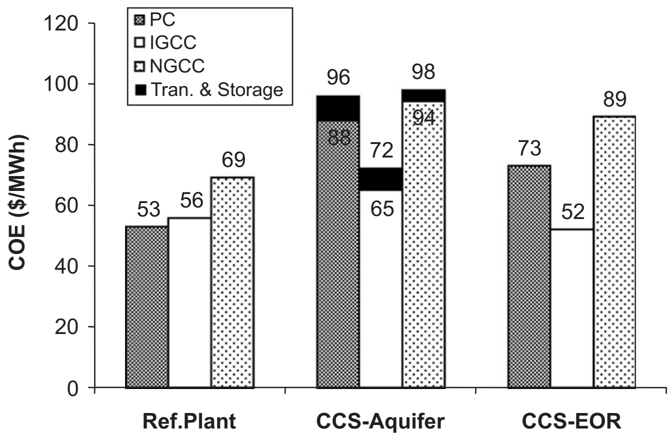

Fig. 2. Cost of electricity ($2005/MWh) for differential capacity factors (CF). CF for reference plants: PC = IGCC = 75%, NGCC = 50%; CF for capture plants: PC = 75%, IGCC = 85%, NGCC = 50%. Capture plant options include geological storage in deep saline aquifers (CCS-Aquifer) or with credits for enhanced oil recovery (CCS-EOR).

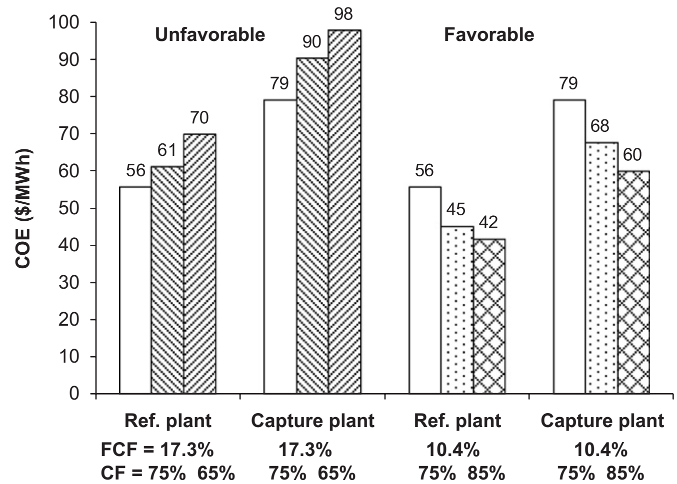

Fig. 3. Cost of electricity ($2005/MWh) for IGCC scenarios. The first (unshaded) bar for each case shows the baseline results presented earlier (based on FCF = 14.8%, CF = 75%). The unfavorable and favorable scenarios (shaded bars) assume higher or lower values of FCF and CF, as shown in the figure legend.

required. Today, however, IGCC plants are still in the early stages of commercialization and are generally more expensive than conventional PC plants. Because of the limited commercial experience and lack of demonstrated reliability under utility operating conditions, IGCC technology also is generally perceived as riskier by the financial community and by many utility companies. This calls into question the common assumption of using the same fixed charge factor (or rate of return) for all technologies in comparative cost studies. Rather, a risk premium would likely be required to finance an IGCC project, at least in the near term. On the other hand, because of the perceived economic and environmental benefits of IGCC in a future carbon-constrained world, government financial incentives have been proposed and recently enacted in the US to facilitate deployment of IGCC power plants.

To reflect uncertainty in IGCC financing, we analyze two additional scenarios posing conditions favorable and unfavorable to IGCC economics. The "Unfavorable" scenario imposes a two percentage-point risk premium on the weighted cost of capital for an IGCC plant, yielding a fixed charge rate of 17.3%, compared to the nominal value of 14.8% in the earlier analyses. In contrast, the "Favorable" scenario assumes some form of government intervention to facilitate the deployment of IGCC plants, such as through loan guarantees, production credits, purchasing agreements or other policy instruments. We model this intervention as an effective reduction in the fixed charge rate, and for illustrative purposes assume a value of 10.4% based on the Harvard 3-Party Covenant proposal (Rosenberg et al., 2004). Finally, we add to each scenario a difference in plant utilization factor to reflect favorable or unfavorable operating conditions over the life of the plant. The unfavorable scenario assumes a levelized capacity factor of 65% to reflect a higher outage rate or a lack of expected load over the plant lifetime. The favorable scenario assumes a more optimistic value of 85%.

Fig. 3 displays the COE for these two scenarios in comparison to the baseline scenario shown earlier. In the Unfavorable case the COE increases by up to 26% for the reference plant and 24% for the capture plant. As a result, the IGCC plant without capture is now even more costly than the reference PC plant, and potentially even more costly than the NGCC plant. With capture, the earlier cost advantage for IGCC largely disappears, and all three systems have similar costs. In contrast, the favorable scenario reduces the COE of the IGCC reference and capture plants by 25% and 24%, respectively. On an absolute basis, the COE of the IGCC-CCS plant in this scenario now falls to a level $9/MWh less than the NGCC reference plant and only $7/MWh more than the PC reference plant with no CO_2 controls. Overall, these scenarios suggest that government policies with respect to IGCC financing will play a critical role in the initial deployment of IGCC technology, with or without CO_2 capture.

7. Effects of plant size and coal quality

In estimating and comparing the costs of PC and IGCC plants, power plant size and coal quality are two additional factors that must be considered. Fig. 4 shows the sensitivity of total plant cost (COE) for capture plants with net power outputs ranging from approximately 250 to 750 MW, with all other parameters kept at the baseline values in Table 1. For the IGCC-CCS cases, the net plant output is determined by the number and type of gas turbines employed. The smallest plant is based on one GE-7A gas turbine while the largest employs three such turbines, as well as three operating gasifiers. All plants have one spare gasifier, which imposes a greater cost per kW on the smallest plant. For the PC-CCS plant, a single supercritical boiler is assumed for all three plant sizes, yielding economies of scale, but multiple trains are employed for the CO_2 capture system because of current size limitations (Rao and Rubin, 2006).

The results in Fig. 4 show that the COE of both plant types increases with decreasing plant size, largely because of higher capital costs per net kW. As a result, the COE of the smallest IGCC plant is 19%, or $14/MWh, more than the largest plant, while for the PC cases, the smallest plant COE is 24%, or $22/MWh, more than the largest. For all three plant sizes, however, the IGCC capture plant retains a lower COE than the PC plant with capture.

Systematic studies of coal quality effects on the economics of IGCC vs. PC capture plants are largely lacking in the open literature; most recent studies consider only the case of plants using bituminous coals. Here, we estimate the cost of our baseline capture plant designs for three additional coal types: an Illinois #6 bituminous coal, with higher sulfur and lower heating value than the Pittsburgh #8 coal; a Wyoming Powder River Basin (PRB) sub-bituminous coal; and a North Dakota lignite coal. The properties of each coal are shown in Table 5.

Using the Pittsburgh #8 coal as the baseline case, Fig. 5 shows the relative change in thermal efficiency and total capital requirement (TCR) of an IGCC capture plant and a PC capture plant for each coal. This figure shows that coal quality has a more pronounced influence on the performance and cost of the IGCC plants than the PC plants. The thermal efficiency of the IGCC plant decreases significantly for the lower-rank coals, mainly because the higher total water input required for the slurry-fed gasifier (see Table 5) leads to large increases in oxygen requirements for these plant designs (Chen, 2005). In contrast, the thermal efficiency of the PC plant declines to a lesser extent, especially for the lignite-based plant. While both plant types also have higher capital costs relative to the baseline case (because of differences in coal flow rates, gas flow rates, equipment sizes, and other factors), the

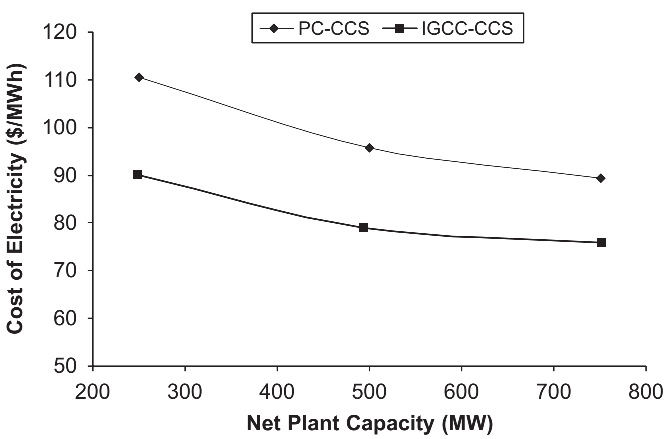

Fig. 4. Cost of electricity ($2005/MWh) as a function of net power plant capacity for capture plants with aquifer storage (baseline assumptions).

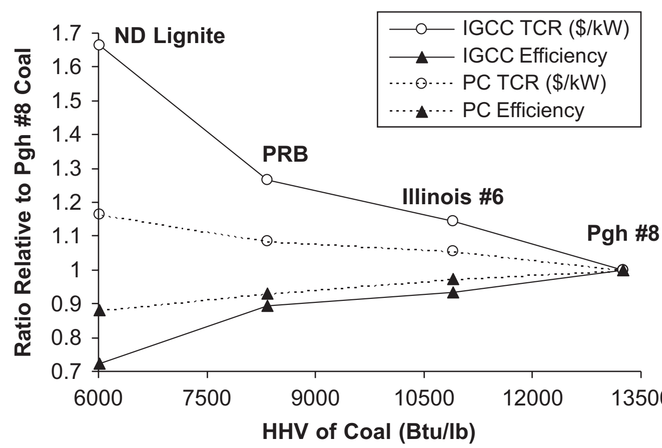

Fig. 5. Effect of coal quality on net plant efficiency and total capital requirement (TCR, $/kW) for PC and IGCC capture plants relative to baseline cases with Pittsburgh #8 coal.

Table 5
As-fired properties of four US coals

Coal type	Pittsburgh #8	Illinois #6	Wyoming PRB	ND lignite
Coal rank	Bituminous	Bituminous	Sub-bituminous	Lignite
HHV (kJ/kg)	30 840	25 350	19 400	14 000
Moisture (%)	5.05	13.00	30.24	33.03
Ash (%)	7.24	11.00	5.32	15.92
Carbon (%)	73.81	61.20	48.18	35.04
Hydrogen (%)	4.88	4.20	3.31	2.68
Nitrogen (%)	1.42	1.16	0.70	0.77
Oxygen (%)	5.41	6.02	11.87	11.31
Sulfur (%)	2.13	3.25	0.37	1.16
Chlorine (%)	0.06	0.17	0.01	0.09
Cost ($/short ton)	33.58	27.46	7.14	9.67
Cost ($/GJ)	1.20	1.19	0.41	0.76
Total water content of IGCC slurry feed				
Moisture + Slurry (%)	34	37	44	55

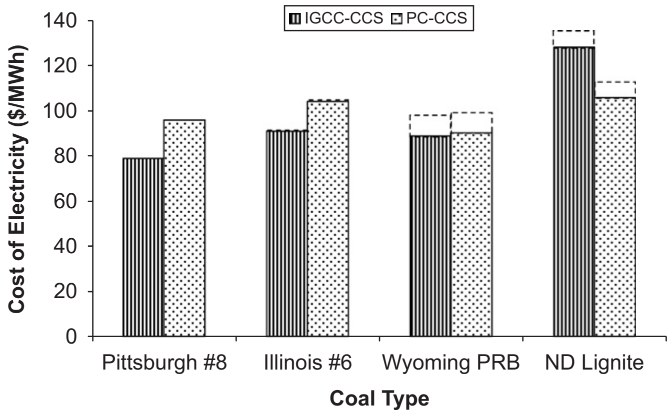

Fig. 6. Effect of coal quality on total cost of electricity for PC and IGCC capture plants. Shaded areas show COE based on different current prices for each coal (see Table 6). Dashed lines show COE based on all coals having the same energy cost ($/GJ) as the baseline Pittsburgh #8 coal.

increases for IGCC plants are greater than for corresponding PC plants, especially for the ND lignite case.

The resulting impacts on total COE for each plant and fuel type are shown in Fig. 6. For the Illinois #6 coal the IGCC plant is again less costly than the PC plant, though by a somewhat smaller margin that the baseline plants (i.e., a COE differential of $12/MWh vs. a difference of $17/MWh for the Pittsburgh #8 case). For the two low-rank coals, however, the situation is quite different. For the subbituminous PRB coal, the COE of the two systems is essentially the same, with a difference of only $1/MWh in favor of the IGCC plant. With lignite, the PC plant is lower in cost than IGCC by a considerable margin ($23/MWh). These latter results contrast with a common belief that IGCC plants with capture are generally less costly than new PC plants with capture (as reflected in Table 1). While that conclusion may apply to similarly sized plants using bituminous coals it does not necessarily apply to plants using low-rank coals.

An important caveat in this regard is that all of the current results are based on an IGCC system with a slurry-fed gasifier similar to the prevailing GE design. For low-rank coals, IGCC systems using other gasifier designs (such as those offered commercially by Shell, Conoco-Phillips, and others) may be more suitable and lower in cost than the system modeled here. A recent Canadian study based on a dry-feed gasifier with lignite coal, however, also concluded that an IGCC capture plant was higher in cost than a PC plant with capture (Stobbs and Clark, 2005). Additional studies are needed to assess the performance and cost of alternative IGCC-CCS designs for a broader range of coal types and gasifiers.

8. Impacts of CCS energy requirements

Previous studies have noted the substantial energy requirements (often called energy penalty) associated with CCS systems. CCS energy requirements directly affect the total cost of a plant since any reduction in net output increases the net cost per unit of product or plant capacity. The normalized capital costs ($/kW) and the COE values ($/MWh) shown earlier thus incorporate the cost of additional power plant capacity needed to operate the CCS system.

For post-combustion capture systems, the magnitude of the CCS energy penalty is often expressed as a percentage reduction in power plant output relative to the same plant without CCS (i.e., the plant derating). For IGCC plants, the addition of CO_2 capture technology changes both the net plant output and the fuel input requirements. Thus, a more general definition of the plant derating must be based on the change in net plant efficiency (η), as given by

$$\text{Fractional reduction in plant output (per unit of energy input)} = 1 - (\eta_{ccs}/\eta_{ref}), \tag{1}$$

where η_{ccs} and η_{ref} are the net efficiencies of the capture plant and reference plant, respectively. On this basis, the reduction in output for the three capture plants modeled earlier in this paper are 24% for the PC plant, 14% for the IGCC plant, and 15% for the NGCC plant (Table 3).

An alternative definition of the energy penalty that we propose here is the increase in plant energy input per unit of product or output. We denote this value as EP. It can be expressed in terms of plant efficiencies by the equation:

$$\mathrm{EP} = (\eta_{ref}/\eta_{ccs}) - 1. \tag{2}$$

This measure is arguably more meaningful for quantifying the economic, environmental and resource implications of CCS energy use because it directly determines the increases in plant-level resource consumption, environmental burdens and economic costs associated with producing an increment of some useful product like electricity. Indeed, normalized cost data (e.g., $/kW and $/MWh) already reflect this formulation. For non-economic impacts, this measure directly quantifies the increases per kilowatt-hour in plant fuel consumption, other plant resource requirements (such as chemicals or reagents), solid and liquid wastes, and air pollutants not captured by the CCS system. Indirectly, EP also affords a measure of the upstream life cycle impacts associated with the extraction, storage and transport of the additional fuel and other resources consumed at the power plant.[3] The value of EP, however, is larger than the plant derating values given by Eq. (1). For the three CCS plants in Table 3 the values of EP are 31% for the PC plant, 16% for IGCC, and 17% for the NGCC plant.

Table 6 summarizes the major ancillary impacts of CCS energy requirements for the three case study plants.

[3]The additional energy for upstream activities is not normally included in the energy penalty for CO_2 capture systems. Inclusion of those additional energy requirements would require re-defining the system boundary and system efficiency to apply to the full fuel cycle, rather than only the power plant with CCS. Such an analysis would require additional assumptions about the methods of fuel extraction, processing, transport to the power plant, and the associated energy requirements of those activities.

Table 6
Impacts of CCS system and energy penalties on plant resource consumption and emission rates (capture plant rate and increase over reference plant rate, kg/MWh)

Capture plant parameter	PC-CSS		IGCC-CSS		NGCC-CSS	
	Rate	Increase	Rate	Increase	Rate	Increase
Resource consumption						
Fuel	390	93	364	50	156	23
Limestone	27.5	6.8	—	—	—	—
Ammonia	0.80	0.19	—	—	—	—
CCS Reagents	2.76	2.76	0.005	0.005	0.80	0.80
Solid wastes/byproduct						
Ash/slag	28.1	6.7	34.2	4.7	—	—
FGD residues	49.6	12.2	—	—	—	—
Sulfur	—	—	7.7	1.2	—	—
Spent CCS sorbent	4.05	4.05	0.005	0.005	0.94	0.94
Atmospheric emissions						
CO_2	107	*−704*	97	*−720*	43	*−342*
SO_x	0.001	*− 0.29*	0.011	*−0.13*	—	—
NO_x	0.77	0.18	0.10	0.01	0.11	0.02
NH_3	0.23	0.22	—	—	0.002	0.002

Increases in specific fuel consumption for each plant type correspond directly to the EP values given above. Thus, the PC capture plant requires 31% more coal per kWh than the reference plant. Other increases in resource requirements per kWh for the PC plant include 31% increases in limestone consumed by the flue gas desulfurization (FGD) system (for SO_2 control) and ammonia consumed by the selective catalytic reduction (SCR) system (for NO_x control). Sorbent requirements for the CO_2 capture units also are reported in Table 6, along with the resulting waste streams. Table 6 further shows the increases in ash and slag residues, plus the increases in solids produced by the desulfurization systems for the PC and IGCC plants. The latter residues could constitute either a solid waste or a saleable byproduct, depending on markets for gypsum (PC plant) and sulfur (IGCC plant).

Lastly, Table 6 displays the change in emission rates of criteria air pollutants due to energy penalty effects. For the PC plant, the amine scrubber captures nearly all residual SO_2 in the power plant flue gas, resulting in a net decrease in SO_2 emissions per kWh. For the IGCC system, there is also additional capture of residual H_2S along with CO_2, resulting in a net decrease in SO_2 emissions per kWh. For NO_x, however, the emission rate increases for all three systems, as the CO_2 capture units remove little or no nitrogen. The PC plant exhibits the largest increase since it has the largest NO_x emission rate as well as the largest energy penalty. Increases in NH_3 emissions for the PC and NGCC plants are due mainly to chemical reactions within the amine CO_2 capture system (Rao and Rubin, 2002).

9. The role of advanced technology

The case studies in this paper deal only with currently commercial technologies for power generation and CO_2 capture. Significant R&D efforts are underway worldwide to develop more efficient, lower-cost technologies for energy conversion and CO_2 capture (IPCC, 2005). To the extent these efforts prove successful, the environmental and cost impacts of CCS may look very different in the future. Examples of ongoing developments include advanced post-combustion capture systems with reduced energy requirements; oxyfuel combustion systems for coal-fired boilers; advanced IGCC systems incorporating membrane-based oxygen production, improved gasifiers and higher-efficiency gas turbines; and more efficient PC and NGCC plants operating at higher temperatures and pressures. Preliminary assessments indicate the potential for future power plants with CCS to be comparable in cost and performance to current plants without CCS (Chen and Rubin, 2006) although realization of such improvements will require large-scale deployment and operation as well as sustained R&D (Rubin et al., 2006).

10. Conclusions

This paper summarized the results of recent studies of current CO_2 capture costs for fossil fuel power systems, and presented updated comparisons of PC, NGCC and IGCC systems covering a range of assumptions for key parameters. In particular, the effects of higher natural gas prices, differential plant utilization rates, and IGCC financing and operating assumptions were highlighted, along with effects of plant size and fuel quality. Because of the higher natural gas prices now foreseen for electric power plants, NGCC plants were found to be more costly than coal-based plants with or without CCS, contrary to results of recent studies based on gas prices of $4/GJ or less. In comparisons between PC and IGCC plants with CCS, the effects of coal quality were found to have a significant effect on both the absolute and relative costs of both systems. The current study affirmed earlier findings that IGCC plants with CCS generally have a lower total COE than a similarly sized PC plant with CCS for bituminous coals, but found that for low-rank coals IGCC was either comparable in cost (for sub-bituminous coal) or higher in cost (for lignite coal) than a PC plant with capture. Failure to include CO_2 transport and storage costs in addition to CO_2 capture costs also was shown to affect comparisons of alternative systems.

This study also highlighted and characterized the magnitude of CCS energy requirements, and their impacts on plant-level resource requirements and environmental emissions. While CCS technologies offer some co-benefits for air pollution control via the co-capture of sulfurous air pollutants, the increases in specific fuel consumption for current CCS systems has significant negative impacts on plant-level consumption of fuel and chemical reagents, as well as on solids wastes and other environmental emissions relative to a similar plant without CCS. Advanced power generation and CCS technologies offering improved efficiency and lower energy requirements are needed to reduce these impacts, and a number of promising options are under development.

Acknowledgments

Support for this work was provided by the US Department of Energy under Contract No. DE-FC26-00NT40935 from the National Energy Technology Laboratory (DOE/NETL), and by the Carnegie Mellon Electricity Industry Center under grants from EPRI and the Sloan Foundation. The authors are grateful for the assistance of Michael Berkenpas in facilitating use of the IECM computer model for this study, and to Dr. John Davison for contributions to the data underlying Table 1. The authors alone, however, are responsible for the content of this paper.

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