COMPARATIVE ASSESSMENTS OF FOSSIL FUEL POWER PLANTS WITH CO_2 CAPTURE AND STORAGE

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Abstract

Studies of CO_2 capture and storage (CCS) costs necessarily employ a host of technical and economic assumptions regarding the particular technology or system of interest, including details regarding the capture technology design, the power plant or gas stream treated, and the methods of CO_2 transport and storage. Because the specific assumptions employed can dramatically affect the results of an analysis, published studies are often of limited value to researchers, analysts and industry personnel seeking results for alternative assumptions or plant characteristics. In the present paper, we use a generalized modeling tool to estimate and compare the emissions, efficiency, resource requirements and costs of PC, IGCC and NGCC power plants on a systematic basis. This plant-level analysis explores a broader range of key assumptions than found in recent studies we reviewed. In particular, the effects on cost comparisons of higher natural gas prices and differential plant utilization rates are highlighted, along with implications of financing and operating assumptions for IGCC plants. The impacts of CCS energy requirements on plant-level resource requirements and multi-media emissions also are quantified. While some CCS technologies offer ancillary benefits via the co-capture of certain criteria air pollutants, the increases in specific fuel consumption, reagent use, solid wastes and other air pollutants associated with current CCS systems are found to be significant. To properly characterize such impacts, an alternative definition of the "energy penalty" is proposed in lieu of the prevailing use of this term.

INTRODUCTION

CO_2 capture and storage (CCS) is receiving considerable attention as a greenhouse gas (GHG) mitigation option since it has the potential to allow continued use of fossil fuels with little or no emissions of CO_2 to the atmosphere. This could allow a smoother and less costly transition to a sustainable, low-carbon energy future over the next century [1]. Although technology currently exists to capture the CO_2 generated by large-scale industrial processes, the reliability and safety of a large-scale CO_2 sequestration program remain to be demonstrated to the satisfaction of policy-makers. Even assuming its eventual public acceptance, the cost of CCS technology could pose another barrier to its widespread use as a GHG control strategy. A number of recent studies have estimated CCS costs based on technologies that are either currently commercial or under development. For the most part, these studies have focused on coal-based power plants, which are a major source of CO_2 emissions [2]. While a few of these studies also have noted the ancillary benefits of CCS 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 absent in the current literature.

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 natural gas combined cycle (NGCC) plants, pulverized coal combustion (PC) plants, and coal-based integrated gasification combined cycle (IGCC) 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 been largely ignored in past 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 found for current CCS and power generation technologies.

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REVIEW OF RECENT COST STUDIES

Table 1 summarizes the range of costs for new plants using current commercial power generation and CO_2 capture technologies, as reported in recent studies we reviewed [3-13]. These costs include CO_2 compression, but not CO_2 transport and storage costs, which are not included in most recent studies.

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)*

Cost and Performance Measures	PC Plant		IGCC Plant		NGCC Plant	
	Range low-high	*Rep. value*	**Range low-high**	*Rep. value*	**Range low-high**	*Rep. value*
Emission rate w/o capture (kg CO_2/MWh)	722-941	795	682-846	757	344-364	358
Emission rate with capture (kg CO_2/MWh)	59-148	116	70-152	113	40-63	50
Percent CO_2 reduction per kWh (%)	80-93	85	81-91	85	83-88	87
Capital cost w/o capture ($/kW)	1100-1490	1260	1170-1590	1380	447-690	560
Capital cost with capture ($/kW)	1940-2580	2210	1410-2380	1880	820-2020	1190
Percent increase in capital cost (%)	67-87	77	19-66	36	37-190	110
COE w/o capture ($/MWh)	37-52	45	41-58	48	22-35	31
COE with capture ($/MWh)	64-87	77	54-81	65	32-58	46
Percent increase in COE w/capture (%)	61-84	73	20-55	35	32-69	48
Cost of CO_2 avoided ($/t CO_2)	42-55	47	13-37	26	35-74	47
Cost of CO_2 captured ($/t CO_2)	29-44	34	11-32	22	28-57	41
Energy penalty for capture (% MW_{ref})	22-29	27	12-20	16	14-16	15

*Definitions: $MW_{re\,f}$ = reference plant net output; COE=cost of electricity; Rep. value=representative value; PC=pulverized coal; NGCC=natural gas combined cycle; IGCC=integrated gasification combined cycle. Notes: Ranges and representative values are based on recent studies reviewed (see text). Capture costs include compression. Cost of CO_2 avoided is based on the given plant type wit and without capture, but excluding transport and storage. NGCC cases based on natural gas prices averaging US$3/GJ. Coal prices average $1.3/GJ. Plant sizes range from 400-1200 MW (typical=550 MW).

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 variability 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 environmental control systems. The contribution of different factors to overall cost is illustrated by Rao and Rubin [11] for the case of a PC plant with CO_2 capture. Although Table 1 reflects a range of assumptions and perspectives for each of the three power systems, the general conclusion that emerges from recent studies is that the total cost of electricity 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 COE without capture, while IGCC plants tend to be less expensive when current CO_2 capture systems are added. Because costs depend on many factors, the generalizations above do not apply in all cases. To date, however, only a few studies have performed systematic analyses of both coal-based and NGCC plants with CO_2 capture. As elaborated below, recent studies of NGCC systems in particular have used fuel price and other assumptions that today appear questionable. Thus, we attempt here to explore a broader range of conditions that affect comparative costs.

ANALYTICAL METHOD FOR CURRENT 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 modeling tool developed by Carnegie Mellon University for the U.S. Department of Energy's National Energy Technology Laboratory (DOE/NETL) [14]. It has been used previously to characterize the costs of PC plants using an amine-based CO_2 capture system [11]. The IECM has now been expanded to include NGCC and IGCC plants with and without CO_2 capture and storage, based on current commercial technologies. Additional models of advanced technologies are currently under development.

As with the PC plant, the new NGCC and IGCC models employ fundamental mass and energy balances, together with empirical data where needed, to quantify overall plant performance, resource requirements and emissions. Plant and process performance model are linked to a companion set of engineering economic models that calculate the capital cost and annual operating and maintenance (O&M) costs of individual plant components, and the total cost of electricity (COE) for the overall plant. Detailed documentation describing each of the power systems and component models is available elsewhere [14-17]. 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.

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 approximately $4/GJ). Table 2 summarizes other key assumptions for this "baseline" analysis. In each case, the "reference" plant is a 500 MW baseload facility without CO_2 capture, while the "capture" plant refers to a similar facility with CCS. For the PC unit, the gross plant size with capture is increased to maintain a net output of approximately 500 MW (in contrast to most studies, which assume the reference plant is derated). The NGCC and IGCC plants retain the same equipment sizes as the reference plant since gas turbines are available only in certain sizes. Both the PC and NGCC employ an amine-based system for 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 underground aquifer, while an alternative case assumes CO_2 is first used for enhanced oil recovery (EOR), thus generating a cost credit for the CCS system. Some of the 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 2. Key assumptions for the baseline analysis

Parameter	PC[a]		IGCC[b]		NGCC[c]	
	Ref	Capture	Ref	Capture	Ref	Capture
Fuel used	U.S.Appalachian bituminous coal [d]				Natural gas [e]	
Gross plant size (MW)	575	710	606	596	517	517
Net plant output (MW)	524	492	527	492	507	432
Net plant efficiency, HHV (%)	39.3	29.9	37.5	32.4	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 ($/GJ, HHV)	1.2	1.2	1.2	1.2	4.0	4.0
CO_2 capture system		Amine		Shift+Selexol		Amine
CO_2 capture efficiency (%)		90		90		90
CO_2 transport cost ($/tonne CO_2) [f]		3.2		3.2		3.2
Geologic storage cost ($/tonne CO_2)		5.0		5.0		5.0
EOR storage credit ($/tonne CO_2)		10.0		10.0		10.0

[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 Texaco quench gasifier (2 + 1 spare), 2 GE 7FA gas turbine, 3-pressure reheat HRSG. 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 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. With capture, all three plants remove 90 percent of the flue gas (or fuel gas) CO_2, but emissions rates per MWh are reduced by 87 to 88 percent because of the CCS energy penalties. Without CO_2 capture, the NGCC plant has the lowest levelized cost of electricity at $43.1/MWh, while the IGCC plant is highest at $48.3/MWh. With CCS, the gas-fired plant is again the lowest-cost system, but now the IGCC plant has a lower COE than the PC unit. Based on the assumptions outlined in Table 2, the cost of CO_2 transport and storage accounts for 4 to 10 percent of the total COE for these cases.

Table 3. Results for the baseline cases using the IECM

Parameter	Units	PC		IGCC		NGCC	
		Ref	**Capture**	**Ref**	**Capture**	**Ref**	**Capture**
CO_2 emission rate	kg/MWh	811	107	817	97	367	43
CO_2 captured	kg/MWh		959		850		387
Total capital requirement	$/kW	1205	1936	1311	1748	554	909
COE [a] (capture only)	$/MWh		74.1		62.6		58.9
Cost of electricity (total)	$/MWh	46.1	82.1	48.3	69.6	43.1	62.1
Cost of CO_2 avoided [b]	$/t$CO_2$		51.2		29.5		58.7
CCS energy penalty	(out/in) %		23.9		13.8		14.7
	(in/out) %		31.4		16.0		17.2
Assuming EOR credit							
Cost of electricity [a]	$/MWh	46.1	67.6	48.3	56.7	43.1	56.2
Cost of CO_2 avoided [b]	$/t$CO_2$		30.5		11.6		40.5

[a] Levelized cost of electricity in constant 2001US$, excluding cost of CO_2 transport and storage.
[b] All values are relative to the reference plant for the same system.

The case study results in Table 3 are consistent with those of other recent studies (Table 1), although the higher gas price used here makes NGCC more costly than in most previous studies. Note, too, that the exclusion of transport and storage costs (as in many cost studies) can affect the comparative ranking of different systems. This is seen in Table 3 for the case of EOR storage, where the IGCC plant becomes the lowest-cost system because the greater amount of CO_2 captured generates larger credits relative to NGCC. Finally, Table 3 shows that the cost of CO_2 avoided ($/tonne CO_2) is highest for the NGCC plant and lowest for the IGCC plant in both scenarios. This reflects differences in both the COE and quantity of CO_2 captured for each system. Note that the plant type with the lowest avoidance cost is not necessarily the one with the lowest COE.[2]

EFFECTS OF GAS PRICE AND PLANT DISPATCH

Two assumptions that are especially important in cost comparisons involving NGCC plants are the natural gas cost and the plant utilization factor. Recent studies of NGCC plants have in most cases assumed natural gas prices of approximately $2-3/GJ over the life of the plant, reflecting the prevailing prices and outlook of the late 1980s and early 1990s in many parts of the world. Consistent with these low prices was the assumption of a high annual load factor (capacity factor) for NGCC units, typically 80 to 90 percent for the studies reflected in Table 1.

In the U.S., the low COE estimated on this basis led to significant investments in simple and combined cycle gas plants over the past decade. However, where coal-fired plants are also available, much of the new gas-fired capacity today goes unutilized. As gas prices have more than doubled over the past five years, average utilization rates for gas turbine-based plants in the U.S. have fallen to as low as 30 percent (see Figure 1). These low capacity factors reflect the fact that power plant dispatch is based on the variable operating cost (VOC) of a unit, not on its total cost of generation (including capital costs). Thus, as natural gas prices have 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 [18] illustrates this approach, which results in different utilization rates for different plant types, depending on the carbon constraint and other factors.

[2] For a single facility, the cost of CO_2 avoided is based on the same plant type with and without CCS, and is defined as: $[(COE)_{ccs} - (COE)_{ref}] / [(CO_2/kWh)_{ref} - (CO_2/kWh)_{ccs}]$. An avoidance cost also can be calculated for any other combination of assumed reference plant and capture plant (e.g., an NGCC reference plant compared to a PC capture plant), or any aggregation of plants with and without a carbon constraint. These cases typically reflect assumptions about what plant types would be built in a particular situation. The resulting cost per tonne values in such cases may differ significantly from those defined here. To help avoid misunderstanding or confusion about the meaning of CO_2 avoidance cost, we use that term sparingly in this paper, preferring instead to emphasize the impact of CCS on the cost of electricity production for a given plant type. From these data, a cost of CO_2 avoided can be calculated for any desired combination of plant types and operating assumptions.

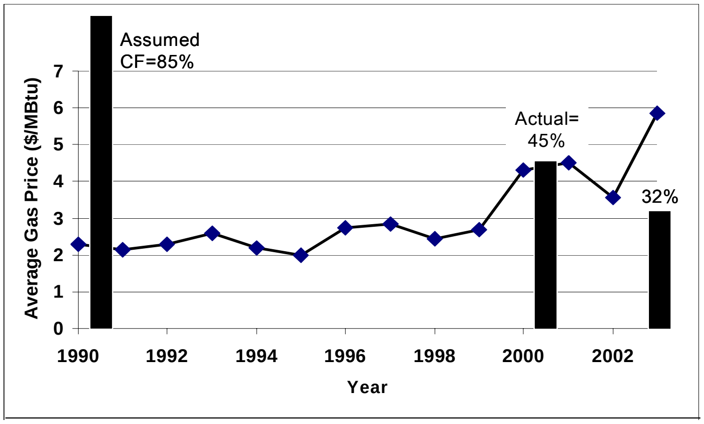

Figure 1. Recent trend in average price of natural gas for U.S. electric utilities. Vertical bars show typical capacity factor assumption for NGCC CCS cost analyses and recent actual values for U.S. plants. [19, 20]

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 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 utilization rates (as previously assumed), but that NGCC units would have increasingly lower capacity factors as gas prices increased. Based on Figure 1, this scenario assumes a 50% capacity factor for the NGCC reference plant. For the capture plants, IGCC units, having the lowest VOC, would be utilized more than PC plants, while NGCC capture plants, having the highest VOC, would be utilized least.[3] For illustrative purposes, we show results for capacity factors of 85%, 75% and 50% for the IGCC, PC and NGCC plants, respectively. The resulting COEs are shown in Figure 2. Compared to the earlier (Table 3) results based on equal capacity factors for all three plants, the qualitative difference is that the IGCC plant now emerges as the least-cost option rather than NGCC. For the PC plant, the cost of CO_2 capture alone is comparable to the NGCC system, but the overall COE is higher because of the added costs of CO_2 transport and storage. However, if the CO_2 were used for EOR, the PC plant with capture becomes less expensive than NGCC owing to credits from CO_2 sales.

Table 4. Differences in total variable operating cost (VOC) relative to the PC plant* ($/MWh)

Plant	Fuel Price	Reference Plant	Capture Plant
PC	$1.2/GJ	(Base case – ref)	(Base case – ccs)
IGCC	$1.2/GJ	~0	-9
NGCC	$2.2/GJ	+3	-7
NGCC	$4.0/GJ	+16	+8
NGCC	$5.8/GJ	+29	+24

*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.

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 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

[3] A sufficiently high carbon tax would change this result. For the plants shown here, a tax on CO_2 emissions of $400/tonne CO_2 ($1730/tonne C) would be required to equalize the VOC for the IGCC and NGCC capture plants at a natural gas price of $4.50/mscf. Such values far exceed those typically considered in the literature on power plant GHG controls.

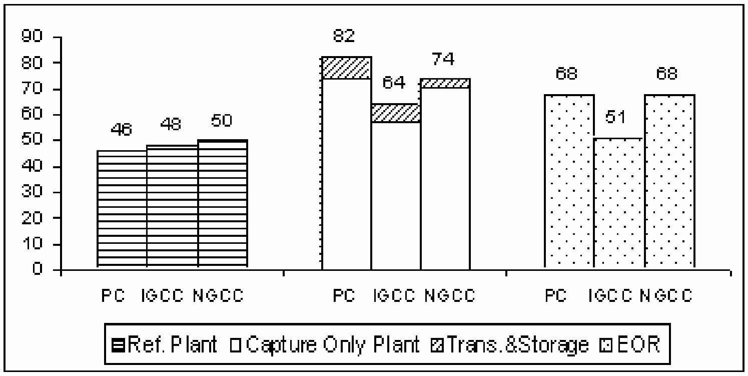

Figure 2. Cost of electricity ($/MWh) for differential capacity factors (CF). (CF for reference plants: PC=IGCC=75%, NGCC=50%; CF for capture plants: PC=75%, IGCC=85%, NGCC=50%)

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 might be required to finance an IGCC project. On the other hand,because of the perceived benefits of IGCC with CO_2 capture, several efforts are underway to develop more attractive financing and ownership arrangements in order to facilitate deployment of IGCC in the U.S. power market. If successful, this would preferentially benefit IGCC technology.

To reflect some of the uncertainty in IGCC financing, we analyze two additional scenarios reflecting conditions favorable and unfavorable to IGCC economics. The "Unfavorable" scenario imposes a 20 percent risk premium on the weighted cost of capital for an IGCC plant, yielding a fixed charge rate of 17.3 percent, compared to the nominal value of 14.8 percent used 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 percent based on the Harvard 3-Party Covenant proposal [19]. 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 percent 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 percent.

Figure 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 25 percent for both the reference and capture plant. In contrast, the Favorable scenario yields up to 27 percent reduction in COE for both the reference and capture plant. On an absolute basis, the COE of the IGCC capture plant is comparable to a PC plant without capture in this scenario.

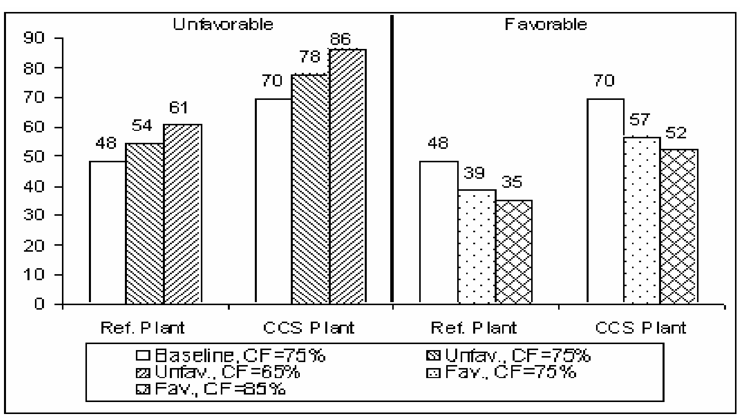

Figure 3. Cost of electricity ($/MWh) for the two new IGCC scenarios. Capacity factor values shown in the legend; fixed charge factor= 14.8% (baseline), 17.3% (unfavorable) and 10.4% (favorable)

CCS ENERGY PENALTY IMPACTS ON COSTS, RESOURCE CONSUMPTION AND ENVIRONMENTAL EMISSIONS

Previous studies have called attention to the significant energy penalties associated with CO_2 capture and storage. The energy penalty of CCS is commonly defined as the reduction in plant output for a constant fuel input (i.e., the plant derating). For some types of facilities, like IGCC plants, the addition of CO_2 capture technology changes both the net plant output and the fuel input. Thus, a more general definition of the energy penalty is based on the change in net plant heat rate or efficiency (η) as given by the following equation:

$$EP = 1 - (\eta_{ccs} / \eta_{ref}) \qquad (1)$$

where EP is the energy penalty (fractional reduction in output), and η_{ccs} and η_{ref} are the net efficiencies of the capture plant and reference plant, respectively. As indicated in Table 3, the energy penalties for the three systems modeled in this paper are 24% for the PC plant, 14% for the IGCC plant, and 15% for the NGCC plant. These energy penalties significantly affect the cost of CO_2 capture and storage since a reduction in the net plant output is reflected in higher costs per unit of product and plant capacity. Thus, the normalized capital cost ($/kW) and the overall cost of electricity ($/kWh) shown earlier both incorporate the energy penalty effects, reflecting the added cost of power plant capacity needed to operate the CCS system.

To assess the environmental and resource implications of CCS energy requirements, we propose an alternative definition of the energy penalty that is arguably more useful for this purpose, namely the increase in plant input per unit of product or output. We denote this value as EP*. It is related to EP in Equation (1) by:

$$EP^* = EP / (1 - EP) = (\eta_{ref} / \eta_{ccs}) - 1 \qquad (2)$$

This measure is more meaningful because it directly quantifies the increases in resource consumption and environmental burdens associated with producing an increment of some useful product like electricity. In the case of a power plant, 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 additional fuel and other resources consumed. Numerically, EP* is larger than EP, as seen in Equation (2). The values of EP* for the three case study technologies are 31% for the PC plant, 16% for IGCC, and 17% for the NGCC plant. If current CCS technologies were deployed on a large scale, increases of these magnitudes for a given electricity demand would indeed be significant.

Table 5 summarizes the major ancillary impacts of CCS energy requirements for the three case study plants. Increases in specific fuel consumption correspond directly to the EP* values given above. Other increases in resource requirements for the PC plant include 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 5, along with the resulting waste streams. Table 5 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 5 displays the increased 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 some additional capture of residual H_2S along with CO_2, but the net effect is still an increase in emissions per kWh. For NO_x, 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 [11].

Table 5. Impacts of CCS system and energy penalties on plant resource consumption and emission rates (capture plant rate and increase over reference plant rate)

Capture Plant Parameter	PC		IGCC		NGCC	
	Rate	**Increase**	**Rate**	**Increase**	**Rate**	**Increase**
Resource Consumption	**(all values in kg/MWh)**					
Fuel	390	93	361	49	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	-	-	7.53	1.04	-	-
Spent CCS sorbent	4.05	4.05	0.005	0.005	0.94	0.94
Atmospheric Emissions						
SO_x	0.001	- 0.29	0.33	0.05	-	-
NO_x	0.77	0.18	0.10	0.01	0.11	0.02
NH_3	0.23	0.22	-	-	0.002	0.002

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 environmental control. To the extent these efforts prove successful, the environmental and cost impacts of CCS may look very different in the future. Ongoing development of the IECM at Carnegie Mellon will soon include preliminary cost and performance models for a number of advanced power systems and CO_2 capture options, including oxyfuel combustion, advance (membrane-based) oxygen production, advanced IGCC systems (incorporating improved gasifiers and gas turbines), and more efficient PC and NGCC plants using post-combustion capture technologies. These new models will be used for future assessments of alternative CCS options for new and existing fossil fuel power plants.

CONCLUSIONS

This paper has summarized the results of recent studies of CO_2 capture costs for fossil fuel power systems, and presented new comparisons of PC, NGCC and IGCC systems covering a wider range of assumptions for key parameters. In particular, the effects of higher natural gas prices and differential plant utilization rates were highlighted, along with plant financing and operating assumptions for IGCC plants. 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. Using the IECM computer model, we also highlighted the ancillary impacts of CCS energy requirements on plant resource requirements and environmental emissions. While some CCS technologies offer ancillary benefits via the co-capture of criteria air pollutants, the increases in specific fuel consumption, reagent use, and solid wastes associated with current CCS systems are significant. Advanced power generation and CCS technologies offering improved efficiency and lower energy requirements are needed to reduce these impacts.

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