Identifying Cost-Effective CO_2 Control Levels for Amine-Based CO_2 Capture Systems

Anand B. Rao* and Edward S. Rubin

Department of Engineering and Public Policy, Carnegie Mellon University, 129 Baker Hall, 5000 Forbes Avenue Pittsburgh, Pennsylvania 15213

Studies of CO_2 capture and storage (CCS) from coal-fired power plants typically assume a capture efficiency near 90%, although the basis for a particular choice usually is not discussed. Nor do studies systematically explore a range of CO_2 capture efficiencies to identify the most cost-effective levels of CO_2 control and the key factors that affect such levels. An exploration of these issues is the focus of this paper. As part of the United States Department of Energy's Carbon Sequestration Program, we have developed an integrated modeling framework (called IECM-*cs*) to evaluate the performance and cost of alternative CCS technologies and power systems in the context of plant-level multipollutant control requirements. This paper uses IECM-*cs* to identify the most cost-effective level of CO_2 control using currently available amine-based CO_2 capture technology for PC plants. Two general cases are of interest. First, we examine the effects of systematically increasing the CO_2 capture efficiency of an amine-based system for PC applications over a broad range. We report two measures of cost: (i) capital cost and (ii) cost-effectiveness (cost per tonne of CO_2 avoided) relative to similar plants without CCS. Second, we examine the cost-effectiveness of plant designs that partially bypass the amine capture unit so as to achieve low to moderate reductions of CO_2, but at lower overall cost. Results from these cases are compared to the conventional case of a capture unit treating the entire flue gas stream. In each case, we identify the most cost-effective strategies and the key factors that affect those results.

1. Introduction

Technologies that control CO_2 emissions from fossil-fuel combustion sources recently have gained worldwide interest. Although much of the research efforts are directed at novel concepts and potential breakthrough technologies, there are also substantial efforts going on to improve CO_2 capture technologies already in use, particularly amine-based CO_2 capture systems. In our previous work, a detailed engineering-economic process model, IECM-*cs*, has been developed to estimate the performance and cost of amine-based CO_2 capture from power plant flue gas.[1,2]

The typical capture efficiency assumed in the literature for amine-based CO_2 capture systems applied to pulverized coal-fired (PC) plants is 90%, with a few studies reporting values in the range of 85%−96%.[3−14] What is the basis for choosing values of capture efficiency in this range? Are the values currently assumed the most cost-effective for the applications chosen? What are the factors that determine or affect the most cost-effective level of CO_2 control? This paper seeks to address these questions.

What do we mean by cost-effective CO_2 control? The dictionary meaning of "cost-effective" is, "being economical in terms of the goods or services received for the money spent". In the context of CO_2 capture and storage (CCS) systems, the most commonly used measure of "services received" is the quantity of CO_2 "avoided", relative to a reference plant without CO_2 capture, while still producing a unit of useful product, such as a kilowatt-hour of electricity. Although the absolute value of plant costs (i.e., capital costs, operating and maintenance (O&M) costs, and total annualized costs) increases with the level of CO_2 removed by the amine-based CO_2 capture system, normalizing the incremental cost of power generation on the amount of CO_2 avoided yields the desired measure of cost-effectiveness for the system. This measure is commonly called the cost of CO_2 avoided, and it is calculated as[15]

$$\text{cost of } CO_2 \text{ avoided (\$/tonne)} = \frac{(\$/\text{kWh})_{ccs} - (\$/\text{kWh})_{ref}}{(tCO_2/\text{kWh})_{ref} - (tCO_2/\text{kWh})_{ccs}} \quad (1)$$

where the subscripts "ref" and "ccs" refer to the reference plant and capture plant, respectively, and kWh refers to the net power production from each of those plants (which differ because of the energy required for CO_2 capture).

One sees from eq 1 that all the factors that affect the cost of electricity and CO_2 emission rate for both the reference plant and capture plant also influence the cost-effectiveness of CO_2 control. These factors include the fuel type and properties; the plant type, size, design, and operation; the CO_2 capture system design; the capital and O&M costs of the system; and the financial factors related to plant construction. In this paper, we use case studies to explore the influence of key factors on the cost-effectiveness of alternative CO_2 control levels.

2. Methodology

This paper uses the IECM-*cs* to identify the key factors that influence the most cost-effective level of CO_2 control using currently available CO_2 capture technologies for PC plants. First, we study the cost breakdown of an amine-based CO_2 capture system to identify the key cost items. We then assess the influence of CO_2 capture efficiency on these cost areas and, ultimately, on the cost of CO_2 mitigation.

Two general cases are of interest. First, we examine the effects of systematically varying the CO_2 capture efficiency of an amine-based system over a broad range for a new PC plant. Second, we examine the cost-effectiveness of plant designs that

* To whom correspondence should be addressed. Tel: +1 (412) 268 5489 or +1 (412) 268 6115. Fax: +1 (412) 268-3757. E-mail: abr@cmu.edu.

10.1021/ie050603p CCC: $33.50
Published on Web 09/27/2005

Table 1. Case-Study Assumptions about the Reference Plant

parameter	value
gross plant sizes	650 and 1000 MWg
plant type	SC[a]
gross plant heat rate	8348 kJ/kWh
plant capacity factor	75%
coal characteristics	
rank	bituminous
high heating value, HHV	30 776 kJ/kg
sulfur content	2.13%
carbon content	73.81%
delivered cost	\$37.10/tonne
delivered cost	\$1.2/GJ
emission standards	2000 NSPS[b]
NO_x controls	low-NO_x burner + selective catalytic reduction
particulate control	electrostatic precipitator
SO_2 control	flue gas desulfurization
CO_2 control	monoethanolamine system
CO_2 capture efficiency	90% (70%−95%)
CO_2 product pressure	13 790 kPa
cost year	2000 (constant dollars)
fixed charge factor	0.148[c]

[a] The nominal case is a supercritical unit. [b] NO_x = 65 ng/J, PM = 13 ng/J, SO_2 = 98% removal (upgraded to 99% with MEA systems). [c] Corresponds to a 30-year plant lifetime with a 14.8% real interest rate (or a 20-year lifetime with a 13.9% interest rate).

partially bypass the CO_2 capture unit to achieve moderate reductions of CO_2. Results from these cases are compared to the case of a capture unit treating the entire flue gas stream.

2.1. Case-Study Assumptions. We first consider the case of adding a post-combustion amine-based CO_2 capture unit to a new conventional coal-fired power plant. The basic assumptions and input parameters are listed in Table 1.

The reference plant (without CO_2 control) burns a medium sulfur bituminous coal (Pittsburgh No. 8) and meets or exceeds the U.S. New Source Performance Standard (NSPS) for coal-fired power plant. The complete plant with multi-pollutant environmental controls is simulated using IECM-*cs*. The flue gas desulfurization (FGD) system is assumed to remove 98% of the flue gas SO_2; this is the best-available technology that yields lower emissions than those required by the present NSPS but is typically required for permitting a new plant in the United States. This assumption also is important because the CO_2 avoidance costs are dependent on the reference plant design as well as the capture plant design.

The CO_2 capture plant is assumed to have the same gross size as the reference plant. [This is the most common assumption in various case studies in the literature.[3,8,9,11] However, the addition of the CO_2 capture system leads to a substantial decrease in net power output. An alternative way of conducting this case study is to assume a larger gross power plant size, such that the net power output with CO_2 capture is the same as that in the reference case. The cost of CO_2 avoidance in that case would be slightly lower (by approximately \$1−2/tonne CO_2), because of the economies of scale for the larger base plant with capture.] The following design changes have been assumed:

(i) Air leakage is reduced to 10% (from the reference plant default value of 19%).

(ii) The FGD system is upgraded to 99% SO_2 removal efficiency.

(iii) A monoethanolamine (MEA)-based CO_2 capture system is added, including CO_2 product compression to 14 MPa. However, the additional cost of CO_2 transport and storage is not included in this analysis.

The values of other important parameters are listed in Tables 2−4.

Table 2. Amine System Performance Model Parameters

performance parameter	nominal value
MEA concentration	30 wt %
lean sorbent CO_2 loading	0.2 mol CO_2/mol MEA
nominal MEA makeup	1.5 kg MEA/tonne CO_2
caustic consumption in MEA reclaimer	0.13 kg NaOH/tonneCO_2
activated carbon use	0.075 kg C/tonne CO_2
gas-phase pressure drop	14 kPa
fan efficiency	75%
sorbent pumping head	200 kPa
pump efficiency	75%
equivalent electrical requirement	14% regeneration heat
compressor efficiency	80%

Table 3. Amine System Capital Costs: Model Parameters and Nominal Values

code	capital cost element	value
A	process area equipment cost	A_1, A_2, A_3, ..., A_{10}
B	total process facilities capital (PFC)	ΣA_i
C	engineering and home office	7% PFC
D	general facilities	10% PFC
E	project contingency	15% PFC
F	process contingency	5% PFC
G	total plant cost, TPC	B + C + D + E + F
H	AFUDC (interest during construction)	calculated
I	royalty fees	0.5% PFC
J	pre-production	1 month fixed O&M cost
K	pre-production	1 month variable O&M cost
L	inventory (startup) cost	0.5% TPC
M	total capital requirements, TCR	G + H + I + J + K + L

Table 4. Amine System O&M Costs: Model Parameters and Nominal Values

O&M cost elements	typical value
Fixed O&M Costs, FOM	
total maintenance cost	2.5% TPC
maintenance cost allocated to labor, $f_{maintlab}$	40% of the total maintenance costs
administration and support labor cost, f_{admin}	30% of total labor cost
operating labor, N_{labor}	two jobs/shift
Variable O&M Costs, VOM	
reagent (MEA) cost	\$1200/tonne
water cost	\$0.8 per 1000 gallons
solid waste disposal cost	\$175/tonne waste

2.2. Identifying the Key Cost Items. Figure 1 shows the breakdown of the annualized cost of the amine-based CO_2 capture system at 90% CO_2 capture efficiency.

The capture system energy requirement emerges as the single largest cost item, because amine-based systems are known to be highly energy-intensive processes. The total annualized capital cost is the second largest cost item. Together, these two items contribute to more than 75% of the total annualized cost of the capture system and, thus, are likely to have a major influence on the overall cost-effectiveness of CO_2 capture. Hence, we have focused on these two cost areas in the subsequent analysis.

3. Results

3.1. Energy Requirement of the CO_2 Capture System. The energy required for the CO_2 capture system is of two types: thermal energy and electrical energy.

3.1.1. Thermal Energy. Heat or thermal energy is required for regeneration of the sorbent. The amount of heat required is

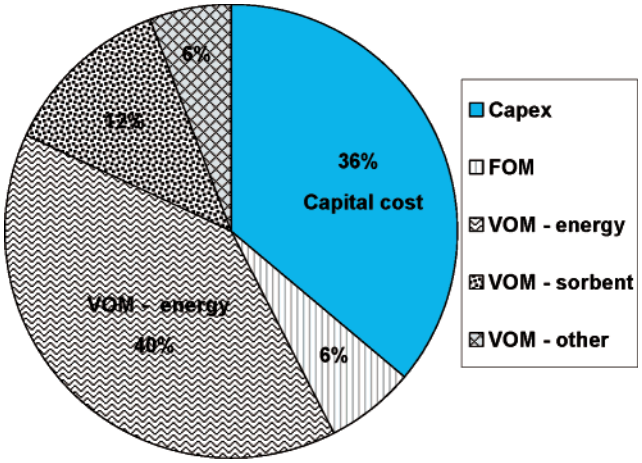

Figure 1. Breakdown of the annualized cost of the amine-based CO_2 capture system at 90% CO_2 capture efficiency, based on the case-study assumptions in Tables 1−4.

a function of the design and operating parameters of the amine-based CO_2 capture system, including sorbent concentration (C), CO_2 mole fraction (y_{CO_2}), lean sorbent CO_2 loading (ϕ_{lean}), and CO_2 capture efficiency (η_{CO_2}). It is estimated using the following equation, which describes a response-surface curve derived on the basis of numerous runs of a process simulation model built in ProTreat:[16,17]

$$H_{reg}\ (\text{MJ/kmol sorbent}) = \exp(2.5919 + 0.0259C - 6.3536\phi_{lean} - 0.0015\eta_{CO_2} - 0.0059y_{CO_2}) \quad (2)$$

In a power-plant application, heat is usually supplied in the form of low-pressure (LP) steam extracted from the steam turbine. This steam extraction leads to a loss in power generation; thus, the thermal energy requirement can be expressed in terms of an equivalent electrical energy penalty, whose value is dependent on the amount and quality of steam extracted. Figure 2a shows the sorbent regeneration energy requirement per unit of CO_2 captured (given in units of kJ/kg CO_2), and the equivalent loss in power generation (given in units of MWh/tonne CO_2), based on detailed studies of LP steam extraction points for modern steam turbines. Higher capture efficiency requires more efficient use of the loading capacity of the sorbent and, hence, more sorbent regeneration energy. Therefore, the specific thermal energy requirement increases as the CO_2 removal efficiency increases.

3.1.2. Electrical Energy. Electrical energy is required to operate capture system mechanical devices such as fans, pumps, and compressors. Because the desired CO_2 product pressure is high (to liquefy the CO_2 for transport), CO_2 compression requires a substantial amount of energy. The energy required for CO_2 compression is estimated using the following equation, which describes a response-surface curve derived on the basis of numerous runs of a process simulation model built in ASPEN-Plus:[17,18]

$$e_{comp}\ (\text{kWh/tonne } CO_2) = \frac{-51.632 + 19.207\ \ln(P_{CO_2} + 14.7)}{\eta_{comp}/100} \quad (3)$$

where P_{CO_2} is the desired CO_2 product pressure (given in units of psig) and η_{comp} is the compressor efficiency (given as a percentage).

A much smaller fraction of the total electrical energy is required to circulate the amine sorbent and overcome the pressure losses in the absorber. The energy required for pumps and fans is estimated using the equation

$$E_{blower}(\text{hp}) = \frac{144Q_{fg}\Delta P_{fg}}{33000\eta_{blower}} \quad (4)$$

where the subscript "fg" denotes flue gas and Q_{fg} and ΔP_{fg} are expressed in units of ft^3/min (actual) and psi, respectively, and the equation

$$E_{pump}\ (\text{hp}) = \frac{Q_{sorbent}\Delta P_{sorbent}}{1714\eta_{pump}} \quad (5)$$

where $Q_{sorbent}$ and $\Delta P_{sorbent}$ are expressed in units of gal/min and psi, respectively.[19]

The model assumes an absorber packing height of 40 ft, based on a detailed column analysis that indicated that the marginal gain in CO_2 capture efficiency by building taller columns was quite low. For this column height, higher capture efficiency is thus achieved via higher L/G, requiring a larger column diameter. Here too, there is a practical limit on the column diameter, which is specified at 40 ft.[21] After that maximum diameter is attained, the flue gas flow rate per column (or train) must be reduced to achieve higher CO_2 capture efficiency via higher L/G. Thus, for a given flue gas flow rate, the number of trains required may increase to achieve higher CO_2 removal. The power requirement of the flue gas blower remains unchanged, because of the constant column height assumption. However, the sorbent pumping power requirement increases with higher capture efficiency. Overall, the total electrical energy requirement per unit of CO_2 captured (MWh/tonne CO_2) decreases as the capture efficiency increases, as shown in Figure 2b. One sees that this is smaller in magnitude than the equivalent thermal energy requirement (expressed in terms of MWh/tonne CO_2) shown previously in Figure 2a, and that the specific electrical energy decreases as the CO_2 removal efficiency increases.

Next, Figure 2c combines the two results shown in Figure 2b to show the total energy penalty (expressed in terms of MWh/tonne CO_2) of the amine-based CO_2 capture system, including both the electrical energy requirement and the equivalent power loss that is due to the sorbent regeneration heat requirement. At 90% capture efficiency, more than half (53%) of the total energy is attributed to sorbent regeneration, whereas the electrical energy requirements for capture and compression are 37% and 10% of the total, respectively. The overall energy requirement is observed to be minimum at a capture efficiency of ∼86% for the case-study conditions.

The net power output of the plant, as a function of increasing CO_2 capture efficiency, is shown in Figure 3. Although the curves may appear linear at the scales presented, the slope of the line gradually increases with higher capture efficiency.

3.2. Capital Cost of the CO_2 Capture System. Here, we examine how the capital cost of the CO_2 capture system varies with the CO_2 capture efficiency. The capital cost model in the IECM-*cs* is based on the number of operating and spare trains for the capture and compression units. Because of limits on the physical sizes of absorber columns and other equipment, there is a maximum capacity that one train can handle. The current cost model is based on detailed information obtained from Fluor Daniel, Inc.,[20,21] who reported a maximum train size of 230 tonne CO_2/h for the amine capture unit [as explained previously,

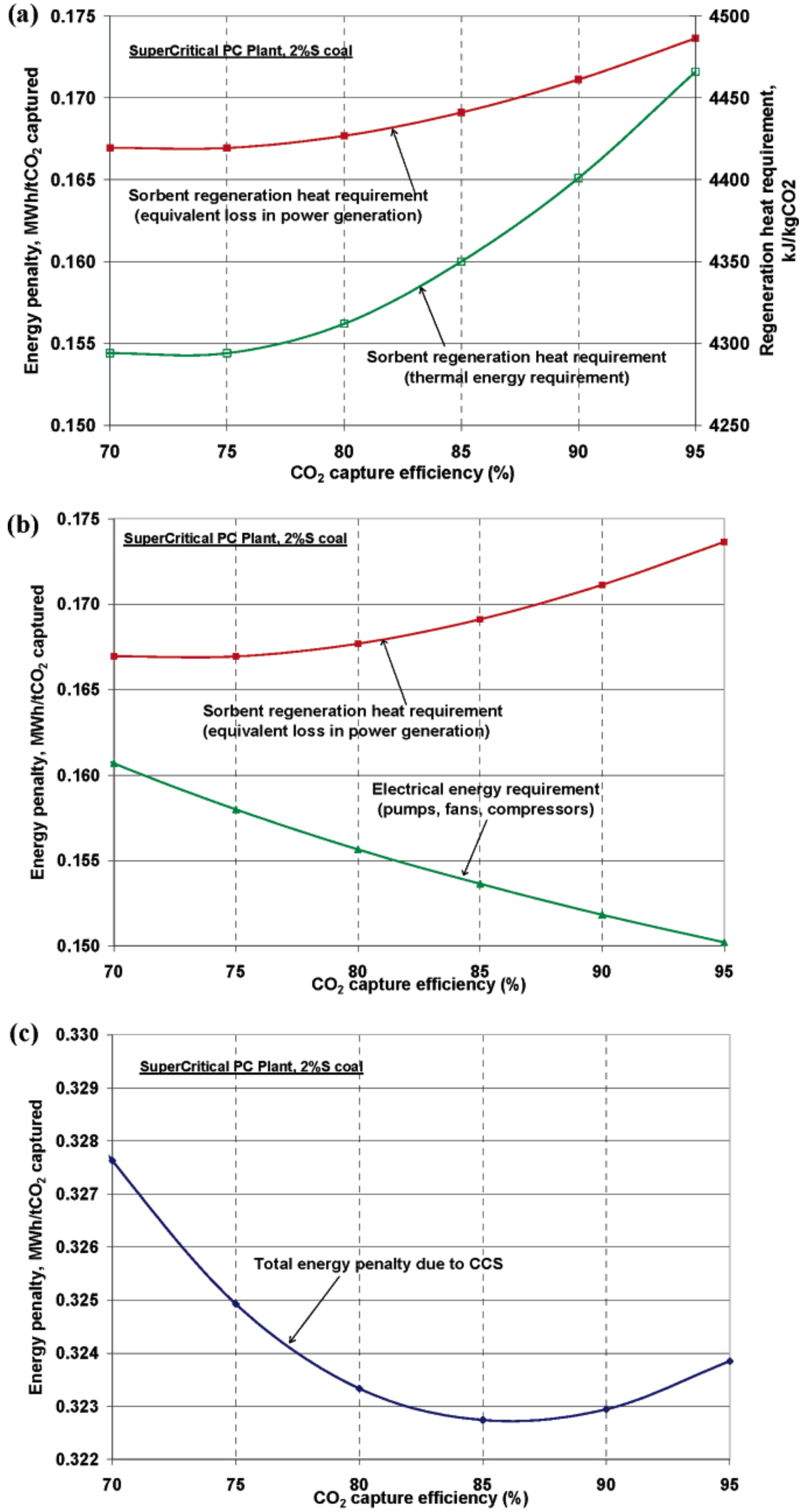

Figure 2. Specific energy requirements of the amine-based CO_2 capture system, as a function of CO_2 capture efficiency: (a) sorbent regeneration heat requirement (kJ/kg CO_2), and the equivalent loss in power generation (MWh/tonne CO_2); (b) electrical energy requirement for capture and compression (MWh/tonne CO_2), and comparison to the equivalent thermal loss in power generation (MWh/tonne CO_2); and (c) total energy requirement (MWh/tonne CO_2) of the amine-based CO_2 capture system, as a function of CO_2 capture efficiency.

the maximum train size is dictated by the maximum column diameter and may be approximated as 230 tonne CO_2/h, according to Fluor Daniel] and 330 tonne CO_2/h for the CO_2 compressors. Figure 4 shows the implications of the maximum train size in estimating the number of trains required for a given capacity of the CO_2 capture plant. Generally, the required

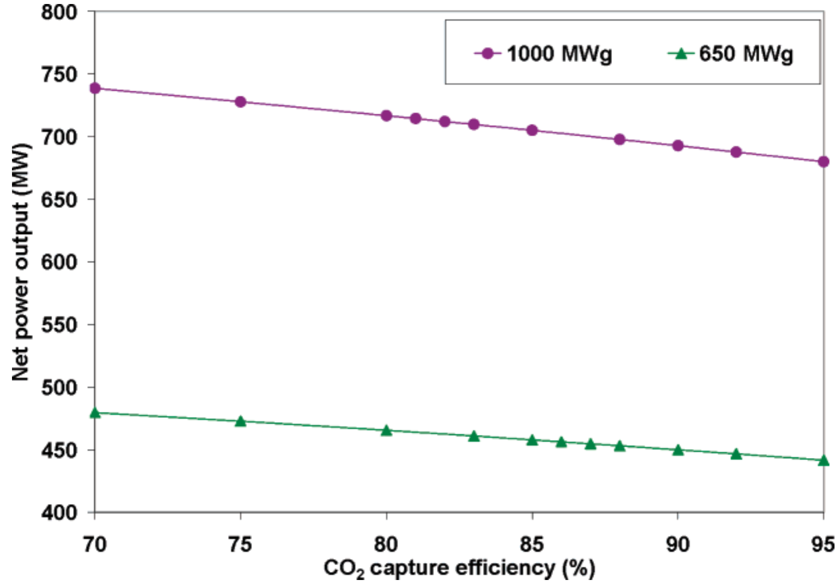

Figure 3. Net power output of the power plant with amine-based CO_2 capture system as a function of CO_2 capture efficiency. (MWg = gross power plant size, before adjustment for auxiliary energy requirements.)

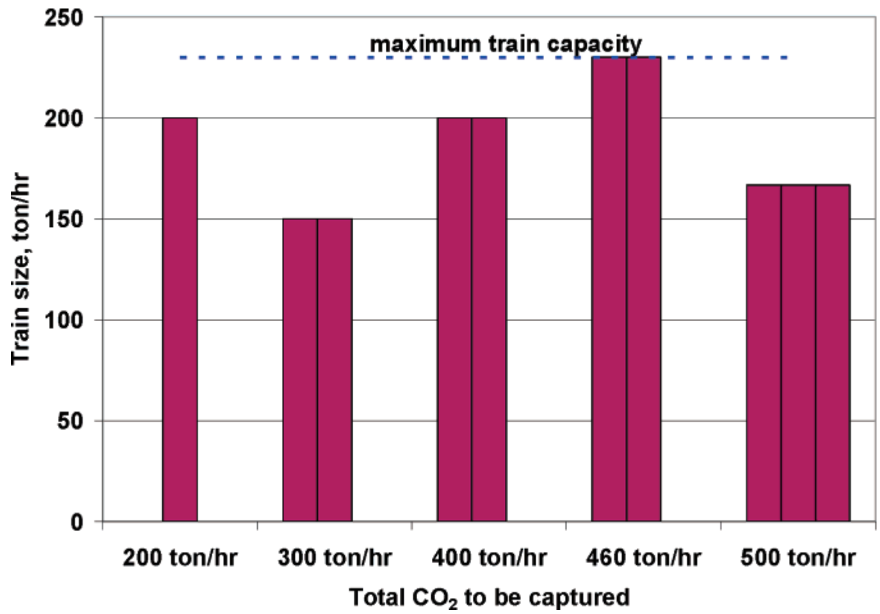

Figure 4. Estimated number and size of trains required, as a function of the total design capacity of the CO_2 capture system. Each bar represents one train.

number of trains is determined by the gross power plant size and the CO_2 removal efficiency assumed. Based on the technical maturity of amine scrubber systems, and the design standards of equipment suppliers, we assume that no spare trains are necessary for this application.

For the case-study assumptions that were described previously, a different number of trains may be required for CO_2 capture and compression. For the 1000 MWg plant, the number of trains for the capture unit increases from three to four at >83% capture efficiency, whereas for the 650 MWg plant, it increases from two to three at >87% capture efficiency. In contrast, the number of compressor trains for the 1000 MWg plant increases from two to three at >81% capture efficiency but remains at two over a broad range of capture efficiencies (70%−95%) for the 650 MWg plant.

Another feature of the cost model is the assumed economies of scale, based on the 0.6 power law commonly used in chemical engineering costing.[22] Thus, the cost per unit of capacity decreases as the train size increases. The cost model also assumes that, for plants with multiple trains, all the trains have the same capacity. Thus, when an additional train is required to accommodate an increase in CO_2 capacity, the new trains are initially smaller and, therefore, more expensive per unit of capacity. Thus, for the 650 MWg plant case, as the number of capture trains increases from two to three (at >87% capture efficiency), the capital cost curve (Figure 5) shows a steplike increase. Similarly, two step changes are observed in the capital cost curve for the 1000 MWg power plant (see Figure 5): one is observed at 81% capture efficiency, when an additional compression train is added, and another is observed at 83% efficiency, when an additional capture train is included.

The influences of scale economies and the number of trains is further illustrated in Figure 6, which shows the CO_2 capture system capital cost normalized on the CO_2 removal capacity. Here, one can clearly see that the economies of scale reduce the unit investment cost for CO_2 capture for a fixed number of trains. However, as the number of trains increases (to handle the increasing quantities of CO_2), the unit cost jumps initially,

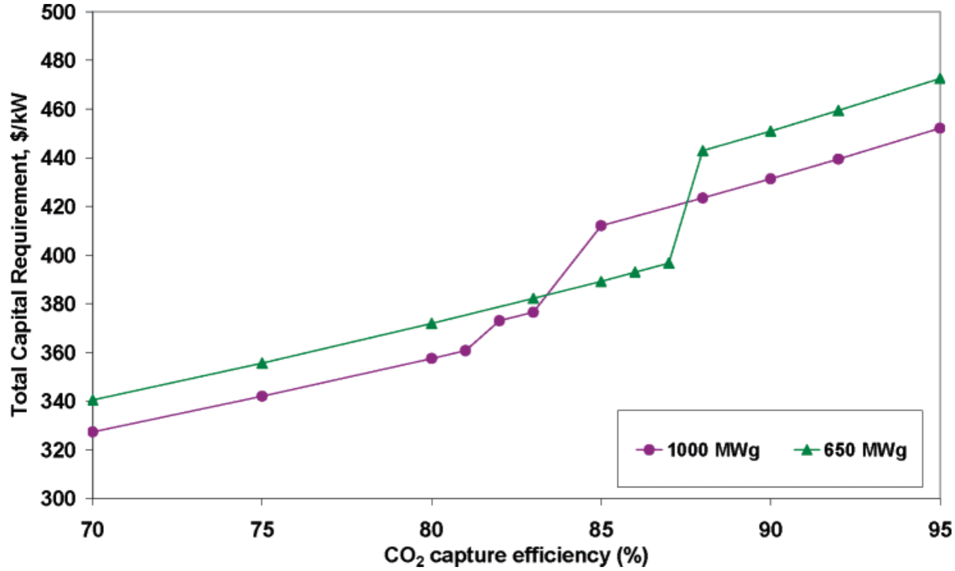

Figure 5. CO_2 capture system capital cost ($/kW) as a function of the CO_2 capture efficiency for two plant sizes.

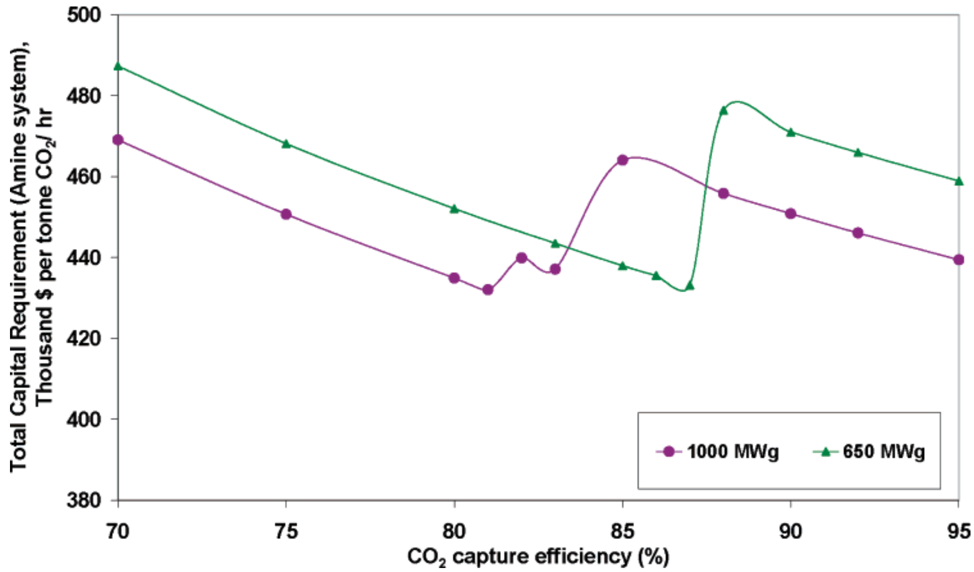

Figure 6. CO_2 capture system capital cost normalized on the CO_2 removal capacity, as a function of the CO_2 capture efficiency for two plant sizes.

and then falls again, with increasing capacity. The location and magnitude of transition points corresponding to changes in the number of trains are dependent on the power plant size and design removal efficiency, as evident in Figure 6. For the 1000 MWg plant, the minimum CO_2 capture system capital cost per tonne CO_2 removed is observed at a capture efficiency of ~81%, whereas for the 650 MWg plant, the minimum is observed at ~87% removal. Note that the capital cost minima in Figures 5 and 6 are different from the 86% capture efficiency at which the total energy requirement of the system was determined to be minimum (Figure 2c). Although the energy penalty strongly affects the net capital cost (via its impact on net power output), other cost factors (especially the number of operating trains for CO_2 capture and compression) also influence the location of the minimum capital cost per unit of CO_2 removed.

3.3. Cost-Effectiveness of the CO_2 Capture System. The overall cost-effectiveness of the CO_2 capture system is evaluated for a range of CO_2 capture efficiencies using eq 1, which was given previously. The results are displayed in Figure 7 for the two case-study plants. The cost-effectiveness curves show structures similar to the normalized capital cost curves (Figure 6), reflecting the importance of the amine system capital cost and energy requirement (which determines net plant capacity) on the overall economics of CO_2 mitigation. For the two plants analyzed, the most cost-effective removal efficiencies are ~81% for the 1000 MWg plant and ~87% for the 650 MWg plant. At these removal efficiencies, the net capacity of the two plants is 714 MW and 455 MW, respectively.

Note, however, that, at 95% capture efficiency, the cost-effectiveness for the 1000 MWg plant is almost as low as the minimum at 81% capture efficiency. Because of the way that train size and number affect capture cost, one sees that there is not always a single value of cost-effective capture efficiency.

3.4. Flue Gas Bypass Option for the CO_2 Capture Systems. Although there is growing anticipation of CO_2 emission limits for coal-fired power plants, it is not clear what levels of CO_2 reduction might be required in the future. Although deep cuts in CO_2 emissions are needed to achieve the goal of stabilizing atmosphere greenhouse gas concentrations,[23] power plants and other emission sources could face low to moderate levels of CO_2 control initially. Thus, we have considered a scenario where the desired CO_2 reduction is lower than the cost-effective levels

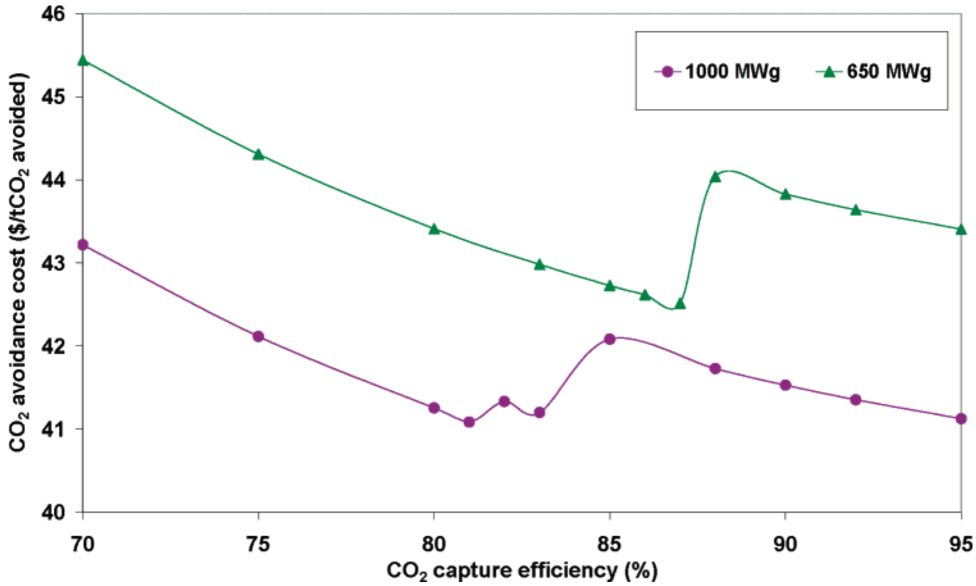

Figure 7. CO_2 mitigation cost as a function of the desired capture efficiency of the CO_2 capture system.

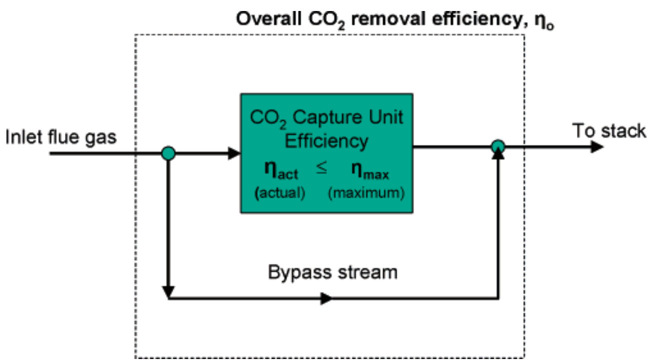

Figure 8. CO_2 capture system with flue gas bypass option.

of CO_2 control previously identified. A potential cost-saving strategy in this case would be to bypass a portion of the flue gas while operating the CO_2 capture system at higher efficiency to achieve the desired overall CO_2 reduction.

"Bypass" is a procedure often used in chemical engineering processes. Here, a fraction of the feed to a process unit is diverted around the unit and combined with the treated output stream, as shown in Figure 8. By varying the fraction of feed that is bypassed, the composition and properties of the product stream (in this case, stack emissions) can be varied. The basic motivation for the bypass option is to achieve the desired product quality at the lowest cost. In the context of CO_2 capture systems, the amine scrubber system would operate at a high CO_2 removal efficiency but treat only a portion of the flue gas stream. Because the cost of the amine unit is dependent primarily on the flow rate of gas treated, the overall cost with the bypass is expected to be lower than the cost of scrubbing all of the gas to achieve a lower CO_2 removal efficiency.

Figure 9 shows the CO_2 mitigation cost estimates for the 650 MWg plant case with and without flue gas bypass. For a given overall capture efficiency, the plant configurations with the bypass have a lower CO_2 avoidance cost, compared to the same plant treating all the flue gas to the desired removal level. The cost savings with the bypass increases as the levels of overall CO_2 removal decrease. In all cases, the minimum avoidance cost is achieved by operating the amine unit at the highest capture efficiency (95%). This indicates that the increased energy costs of higher CO_2 removal in the capture unit (see

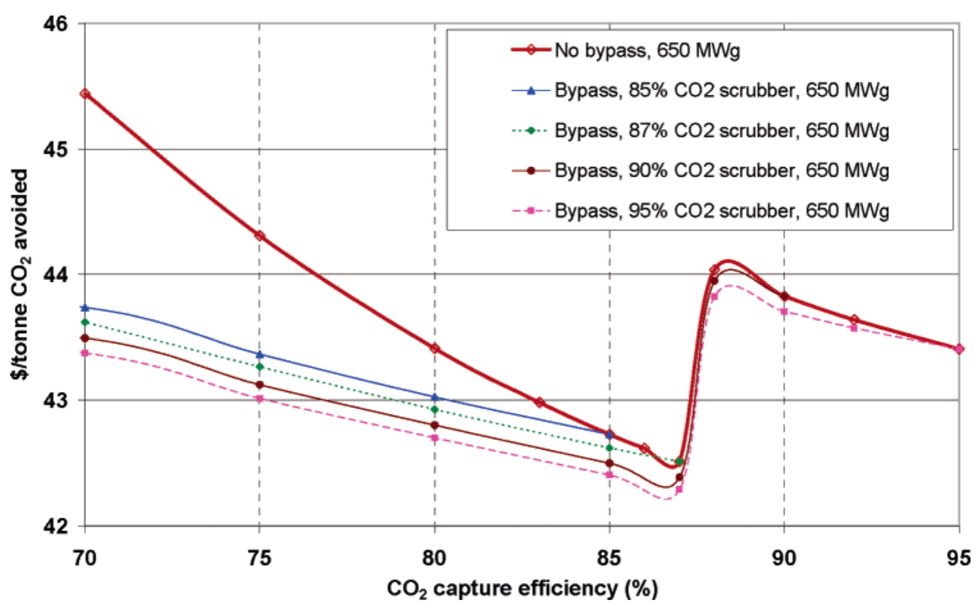

Figure 9. CO_2 mitigation cost as a function of the desired capture efficiency, with and without the flue gas bypass.

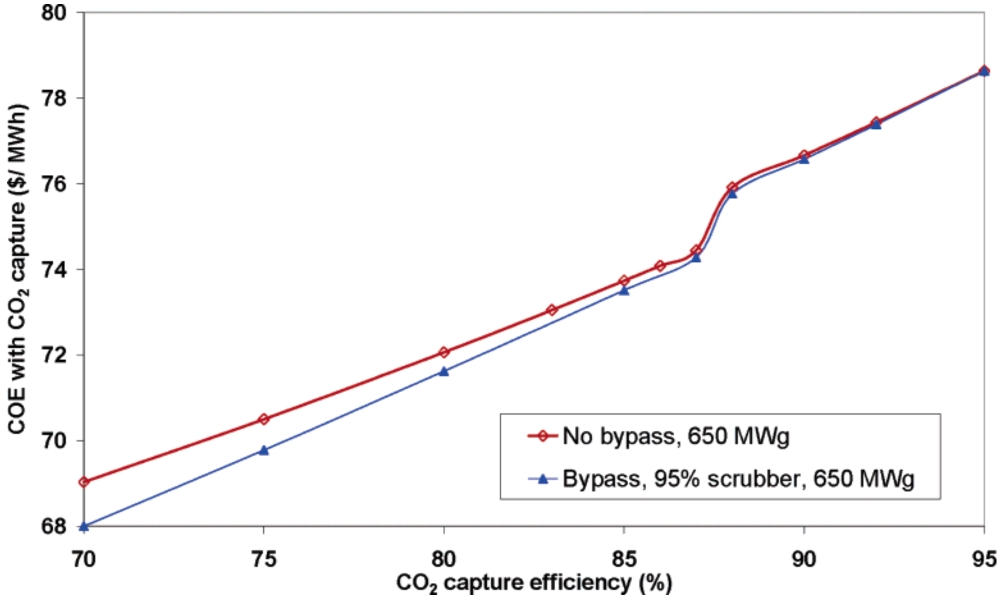

Figure 10. Cost of electricity ($/MWh) as a function of the desired capture efficiency, with and without the flue gas bypass.

Figure 2c) are more than offset by the reduced cost of processing and compressing a smaller flue gas stream.

As previously noted, there are local maxima and minima on this curve, because of train size effects; thus, the most cost-effective level of CO_2 capture may vary with plant size. Also note that, although lower CO_2 removal levels (e.g., <85%) are not as cost-effective as the optimal level, the cost of electricity generation generally decreases as the capture efficiency decreases. Figure 10 illustrates the reductions in the cost of electricity (COE) achieved with a partial bypass for the 650 MWg case-study plant.

Note that this analysis does not take into account the variety of dispatch constraints that a power plant may encounter in different situations or locations. To the extent that the levelized annual capacity factor of a particular plant differs from the value assumed in this analysis, the cost advantages from flue gas bypassing may be greater or less than those presented here.

4. Concluding Remarks

The analysis presented here showed that the most cost-effective level of CO_2 control is dependent on several plant design factors, including the plant size. For the case studies of supercritical PC plants with amine capture systems, the most cost-effective levels of CO_2 capture efficiency using current technology were estimated to be 81% and 87% for plant sizes of 1000 and 650 MWg, respectively. The study further showed that, if low to moderate levels of CO_2 control are desired, the cost-effectiveness of CO_2 control can be improved by treating only a portion of the flue gas at high capture efficiency, with the remaining fraction of flue gas bypassing the amine system. In all cases, the maximum amine system train size, and its effect on capital cost, also was observed to have a major influence on the cost-effectiveness of CO_2 capture and the optimal (least costly) level of control.

Future improvements to current amine-based CO_2 capture systems can have an important influence on the cost and cost-effectiveness of CO_2 capture for post-combustion systems. In our recent expert elicitation study, the development of improved sorbents with lower regeneration energy requirements was identified as the highest priority research and development (R&D) objective for amine capture systems.[24] Such improvements are needed to reduce the large energy requirement of current systems, which is the major contributor to the relatively high cost of this technology. Technological developments that facilitate construction of larger absorber and regenerator trains, as well as CO_2 compressors, also can contribute significantly to a more cost-effective level of CO_2 capture for larger plant sizes.

Acknowledgment

This research was supported by the U.S. Department of Energy's National Energy Technology Laboratory (under Contract No. DE-FC26-00NT40935); by the Center for Integrated Study of the Human Dimensions of Global Change, through a cooperative agreement between the National Science Foundation (SBR-9521914) and Carnegie Mellon University; and by The Teresa Heinz Scholarship for Environmental Research. The authors alone are responsible for the content of this paper.

Literature Cited

(1) *IECM, Integrated Environmental Control Model and User Documentation*; Center for Energy and Environmental Studies, Carnegie Mellon University, Pittsburgh, PA. (Available at www.iecm-online.com.)

(2) Rao, A. B.; Rubin, E. S.; Berkenpas, M. B. An integrated modeling framework for carbon management technologies, Final report to DOE/NETL (Contract No. DE-FC26-00NT40935); Center for Energy and Environmental Studies, Carnegie Mellon University, Pittsburgh, PA, 2004.

(3) Smelser, S. C.; Stock, R. M.; McCleary, G. J. Engineering and economic evaluation of CO_2 removal from fossil-fuel-fired power plants; EPRI Report IE-7365, Volume 1, Project 2999-10, 1991. (This was a research project final report prepared by Fluor Daniel, Inc., for EPRI and IEA.)

(4) Stork Engg Consultancy B.V. Leading options for the capture of CO_2 emissions at power stations; Report No. PH3/14; IEA GHGRDP: Cheltenham, U.K., 2000.

(5) Jeremy, D.; Herzog, H. J. The cost of carbon capture. Presented at Fifth International Conference on Greenhouse Gas Control Technologies, Cairns, Australia, 2000.

(6) Gambini, M.; Vellini M. CO_2 emission abatement from fossil fuel power plants by exhaust gas treatment. Presented at International Joint Power Generation Conference, Miami Beach, FL, 2000.

(7) Simbeck, D.; McDonald, M. Existing coal power plant retrofit CO_2 control options analysis. Presented at Fifth International Conference on Greenhouse Gas Control Technologies, Cairns, Australia, 2000.

(8) ALSTOM Power, Inc., ABB Lummus Global, Inc., ALSTOM Power Environmental Systems, and American Electric Power (AEP). Engineering feasibility and economics of CO_2 capture on an existing coal-fired power

plant; Final report prepared by ALSTOM Power Inc., ABB Lummus Global Inc., ALSTOM Power Environmental Systems and American Electric Power (AEP); Report No. PPL-01-CT-09. (Submitted to Ohio Department of Development, Columbus, OH, and U.S. Department of Energy/ NETL, Pittsburgh, PA, 2001.)

(9) Parsons Infrastructure & Technology Group, Inc. Evaluation of fossil fuel power plants with CO_2 recovery; U.S. Department of Energy (USDOE)/ National Energy Technology Laboratory (NETL)/Electric Power Research Institute (EPRI): Pittsburgh, PA, 2002.

(10) Rao, A. B.; Rubin, E. S. A Technical, Economic, and Environmental Assessment of Amine-Based CO_2 Capture Technology for Power Plant Greenhouse Gas Control. *Environ. Sci. Technol.* **2002**, *36*, 4467−4475.

(11) Parsons, E. L.; Shelton, W. W.; Lyons, J. L. *Advanced Fossil Power Systems Comparison Study*; Final Report prepared for National Energy Technology Laboratory (NETL): Morgantown, WV and Pittsburgh, PA, 2002.

(12) Singh, D.; Croiset, E.; Douglas, P. L.; Douglas, M. A. Techno-economic study of CO_2 capture from an existing coal-fired power plant: MEA scrubbing vs O_2/CO_2 recycle combustion. *Energy Convers. Mgmt.* **2003**, *44*, 3073−3091.

(13) White, C. M.; Strazisar, B. R.; Granite, E. J.; Hoffman, J. S.; Pennline, H. W. Separation and capture of CO_2 from large stationary sources and sequestration in geological formations—coalbeds and deep saline aquifers. *J. Air Waste Manage. Assoc.* **2003**, *53*, 645−715.

(14) Marion, J.; Mohn, N.; Liljedahl, G. N.; Nsakala, N.; Morin, J.; Henriksen, P. Technology options for controlling CO_2 emissions from fossil fuelled power plants. Presented at Third Annual Conference on Carbon Capture and Sequestration, Alexandria, VA, 2004.

(15) Herzog, H. J.; Drake, E.; Adams, E. CO_2 capture, reuse and storage technologies for mitigating global climate change, A White Paper (Final Report), DOE Order No. DE-AF22-96PC01257, Energy Laboratory, Massachusetts Institute of Technology, Cambridge, MA, 1997.

(16) *ProTreat*; Optimized Gas Treating, Inc.; Houston, TX, 2002.

(17) Rao, A. B. A Technical, Economic, and Environmental Assessment of Amine-Based Carbon Capture Systems for Greenhouse Gas Control, Ph.D. Thesis, Carnegie Mellon University, Pittsburgh, PA, 2003.

(18) *Aspen-Plus*; Aspen Technology, Inc.: Cambridge, MA, 2002.

(19) Perry, R. H.; Green, D. W.; Maloney, J. O. *Perry's Chemical Engineers' Handbook*, 7th ed.; McGraw−Hill: New York, 1997.

(20) Fluor Daniel Canada, Inc. Evaluation of technologies for the removal of CO_2 from coal fired power plant flue gas. Report prepared for TransAlta by Fluor Daniel Canada, Inc., Calgary, Alberta, Canada, 1998.

(21) Chapel, D.; Ernst, J.; Mariz, C. Recovery of CO_2 from flue gases: commercial trends. Presented at the Canadian Society of Chemical Engineers Annual Meeting, Saskatoon, Saskatchewan, Canada, 1999.

(22) Peters, M. S.; Timmerhaus, K. D. *Plant Design and Economics*, 4th Edition; McGraw−Hill: New York, 1991.

(23) Third Assessment Report: Climate Change 2001. Published for the Intergovernmental Panel on Climate Change, Cambridge University Press, Cambridge, U.K., 2001.

(24) Rao, A. B.; Rubin, E. S.; Keith, D. W.; Morgan, M. G. Evaluation of Potential Cost Reductions from Improved CO_2 Capture Systems. *Energy Policy*, in press.

Received for review May 20, 2005
Revised manuscript received August 8, 2005
Accepted August 11, 2005

IE050603P