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Fossil electricity and CO_2 sequestration: how natural gas prices, initial conditions and retrofits determine the cost of controlling CO_2 emissions

Timothy L. Johnson*, David W. Keith

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

Stabilization of atmospheric greenhouse gas concentrations will require significant cuts in electric sector carbon dioxide (CO_2) emissions. The ability to capture and sequester CO_2 in a manner compatible with today's fossil-fuel based power generation infrastructure offers a potentially low-cost contribution to a larger climate change mitigation strategy. The extent to which carbon capture and sequestration (CCS) technologies might lower the cost of CO_2 control in competitive electric markets will depend on how they displace existing generating units in a system's dispatch order, as well as on their competitiveness with abatement alternatives. This paper assumes a perspective intermediate to the more common macro-economic or plant-level analyses of CCS and employs an electric system dispatch model to examine how natural gas prices, sunk capital, and the availability of coal plant retrofits affect CCS economics. Despite conservative assumptions about cost, CCS units are seen to provide significant reductions in baseload CO_2 emissions at a carbon price below 100$/tC. In addition, the ability to retrofit coal plants for post-combustion CO_2 capture is not seen to lower the overall cost of CO_2 abatement.

Keywords: Carbon dioxide capture and sequestration; CO_2 emissions mitigation; Electricity generation

1.

Stabilization of atmospheric carbon dioxide (CO_2) concentrations—the goal of the 1992 UN Framework Convention on Climate Change—will require substantial reductions in net emissions. Limiting CO_2 concentrations to a doubling of pre-industrial levels, for instance, will require a reduction in annual global emissions of at least 50 percent from their business-as-usual trajectory by 2050 (Wigley et al., 1996). The need to reconcile this reduction with an economy dependent on fossil fuels presents a fundamental challenge to industrial society.

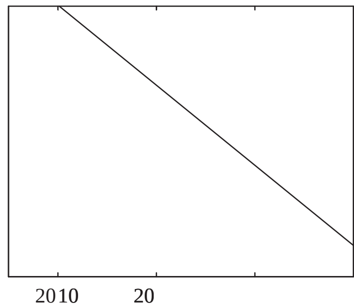
It is uncertain how the needed reductions will be distributed across the economy, but there are several reasons to expect that the electric sector will be an important target for CO_2 mitigation. US electricity

recovered, often remain competitive with newer and more efficient plants (Ellerman, 1996). The long lifetimes of these plants preserve an infrastructure that does not match what would be built given more recent technology and factor (especially fuel) prices. The gradual turnover of this infrastructure, coupled with a trend toward the increased use of natural gas and the availability of more efficient coal technologies will yield an emissions reduction absent a constraint on CO_2, and therefore lower mitigation costs. This effect, however, is

which the model stratifies into three classes to approximate the thermal efficiency distribution of MAAC region plants (EIA, 1999; EPA, 2001). The base model includes only those existing coal plants with a nameplate capacity greater than 100 MW. Five additional technolaccompany significant world-wide adoption of CCS technologies.

This argument applies as well to retrofits of existing coal plants, which are parameterized by four generic variables: a step increase in marginal O&M of 0.5 cents per kWh, a capital cost of 250$/kW (thermal), an energy penalty of 20 percent, and a CO_2 capture efficiency of 90 percent (derived from Simbeck and McDonald, 2001). Note that the model specifies retrofit capital cost as $/ kW thermal (gross) since power output—and, hence, the capital cost in $/kW of net electrical output—vary with both base-unit efficiency and the retrofit energy penalty derating of the original plant. Division of this generic capital cost (in $/kW thermal) by an existing coal plant's thermal efficiency and one minus the retrofit energy penalty yields the plant-specific retrofit capital cost in $/ kW net output.

In order to give a fair accounting of all CCS-related expenses, the baseline model assumes an additional cost of 30$/tC (8.2$/tCO_2) for CO_2 transport and sequestra-thermal-Lmodkelzth'zkrgy.o01 EW$Lthezn.v'bkW-ZGiZJ $Lof.vk'hZ'i



marginal cost generating technologies (coal CCS) supply baseload demand while units with lower capital requirements but higher operating costs (gas CCS) are reserved for short-term peak needs. Second, as the price of carbon emissions increases, marginal cost and carbon-ordered dispatch strategies begin to coincide—a trend consistent with conclusions of the ''Five-Labs'' study (Brown et al., 1998; Interlaboratory Working Group, 1997). Fig. 3 provides snapshots of utilization versus the price of carbon emissions for three layers of the load-duration curve and illustrates this trend for the baseline model: generating units with the lowest CO_2 output—and therefore marginal costs—provide baseload capacity as emissions become more expensive.

• 2

Assessing the costs of CCS as a CO_2 control strategy would be straightforward if competing mitigation alternatives were unavailable and the only choice was between a conventional fossil-electric plant and its counterpart with CO_2 capture. The natural basis for a plant-level analysis is the relationship between the total cost of electricity and carbon emissions per unit of energy generated (Fig. 4). The slope of the line connecting a given plant (defined by generating technology and fuel choice) with its CO_2-capture equivalent is the emissions price threshold above which the latter is preferred. Conventional coal plants, for instance, would be less expensive to build and operate until the value of CO_2 exceeds 100$/tC, beyond which coal with carbon capture is the least-cost option. Likewise, carbon capture is not economical for new gas facilities until the carbon price approaches 200$/tC; with carbon emissions (on a per-kWh basis) roughly half that of coal plants, gas plants have a proportionally higher conventional-to-CCS threshold.

Such comparisons form the basis of a plant-level assessment of CO_2 mitigation costs (e.g., Herzog and Vukmirovic, 1999; David, 2000). As the authors of plant-level studies are careful to note, this approach aims to estimate the cost of making specific emission reductions *given* a set of assumptions about a generating technology and its environment, and necessarily treats the world beyond the plant gate parametrically. *Electric sector* mitigation costs, however, depend on how all units in a power pool interact to meet demand. Competition between fuels, the natural turn-over of existing capacity, and the flexibility of the plant dispatch order affect the evolution of the generating infrastructure and constrain its response to a price on carbon emissions. These factors interact to influence the cost of CO_2 mitigation and are difficult to specify exogenously.

A new coal plant, for example, need not be compared exclusively to its closest CCS equivalent; operators may also choose conventional natural gas or non-fossil renewable technologies as a means of reducing system-wide CO_2 emissions. A plant-level analysis must also assume a static load factor. Yet as new generating units are integrated into an existing power pool, and as electricity demand and factor prices change with time, the dispatch order will vary. There is no reason, of course, that a plant-level analysis could not specify different load factors. The trick, however, would be specifying a value for the base (non-CCS) technology. A new CCS unit would be dispatched up to its available capacity, but base plant dispatch would depend on how all available generating units interact to meet a specific demand profile when both demand and factor prices vary with time. Gas-fired units, for instance, will fall to the bottom of the dispatch order and displace coal plants as carbon prices begin to rise. When a new CCS plant enters it will have the lowest operating costs (except, in this case, for nuclear), and will therefore displace existing conventional units in the dispatch order. The resulting difference in base plant and CCS load factors lowers the mitigation cost at which CCS becomes competitive. That trend is visible here, and explains why—as seen in Fig. 3—CCS enters at a carbon price 25 percent below the Fig. 4 estimate.

Fig. 5 depicts the CO_2 mitigation cost curve derived from the capacity planning model's baseline scenario (focus, for now, on the ''CCS'' and ''No CCS'' lines). Several features are worth noting. First, as was seen in Fig. 3, increased reliance on natural gas units and dispatch re-ordering are the preferred mitigation alternatives for moderate carbon prices, and CCS enters the generating mix only for CO_2 reductions greater than 40-bLplantW

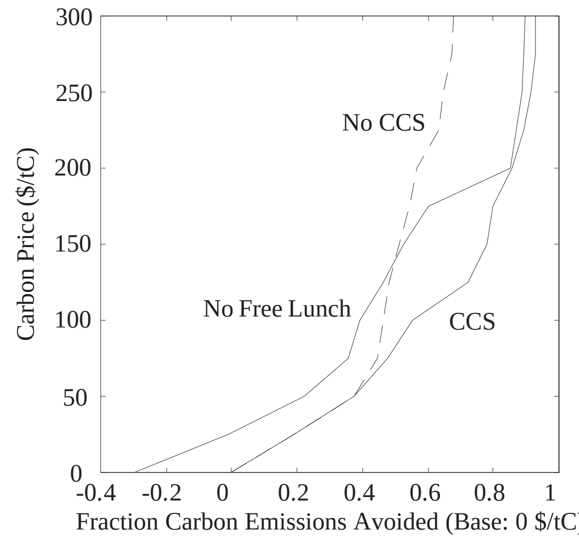


Fig. 5. Carbon mitigation cost curves when CCS technologies are

illustrate how CCS-related mitigation cost estimates depend on context: the competition between alternative abatement options and their utilization in an integrated electric power system. The next section examines how elements of this context influence mitigation costs.

Two points must be kept in mind when assessing the impact of natural gas prices on CO_2 mitigation costs and the adoption of CCS. First, the low natural gas prices prevailing through the 1990s combined with improvements in gas turbine technology to narrow the difference between coal and gas plant generating costs and encourage the adoption of gas units to meet growing demand (Ellerman, 1996; Hirsh, 1999). Second, the CO_2 emissions per unit of energy produced from a natural gas plant are roughly half that of a typical coal plant. Absent a price on carbon emissions, this evolution toward natural gas with its lower carbon intensity therefore yields a ‘‘free lunch’’ reduction in CO_2 emissions—a side benefit that becomes more pronounced when gas prices are low and the initial distribution of generating capacity is dominated by old, and relatively inefficient, coal plants.

The MAAC region exhibits this trend: if demand and factor prices remained constant—with natural gas prices at mid-1990s levels—the MAAC fuel mix would likely evolve from coal to gas, with a concomitant reduction in CO_2 emissions. In a world with constraints on CO_2 emissions, this effect would lower the cost of CO_2 control, providing a benefit that would be absent if the distribution of generating capacity could be continually ‘‘re-optimized’’ to reflect current operating costs. Initial conditions in the form of long-lived sunk capital therefore need to be considered when estimating electric sector mitigation costs.

A scenario in which there is no pre-existing generating capacity and in which demand and factor prices remain fixed at their period 1 levels provides the starting point for determining the extent to which initial conditions matter and the ‘‘free lunch’’ effect reduces mitigation costs. The capacity added in this scenario represents what one would expect to see as initial capacity if the system began in economic equilibrium (45.6 GW NGCC and 19.4 GW GT). A run of the base model with this equilibrium distribution of existing capacity then yields the ‘‘No Free Lunch’’ supply curve of Fig. 5. Mitigation costs are indeed uniformly higher without the secondary reduction in CO_2 emissions.

Natural gas prices, however, have been volatile and their future levels are uncertain. With a serious initiative to reduce CO_2 emissions, for instance, the price of gas would likely rise as economy-wide demand increased. Fig. 6 examines the impact of gas prices by comparing CO_2 mitigation costs for three gas price scenarios (see also Table 3). Note that the unconstrained emissions run of the 3.20$/GJ scenario provides the basis used to calculate the fraction of CO_2 avoided in each case. The low gas price scenario therefore begins with a positive emissions reduction as fuel switching to lower-emission NGCC plants is the least-cost option even in the absence of a price on CO_2 emissions. In contrast, the zero-abatement position of the high gas price scenario nearly coincides with that of the standard run as coal and nuclear currently fill the lower levels of the dispatch order. The higher gas price affects the cost of providing shorter-duration peak demand, but does not significantly impact overall CO_2 emissions.

The reversal in ordering of the gas price scenario mitigation cost curves at higher levels of CO_2 abatement may seem counterintuitive; basic economic considerations, however, provide an explanation. All other things being equal, a decrease in the price of natural gas necessarily lowers generating costs for a given level of CO_2 abatement. The costs of electricity generation (not including the price of CO_2 emissions) under all gas price scenarios, however, must converge as emissions approach zero and the generating mix shifts toward zero-emission coal, (existing) nuclear, and renewable technologies. Plotted against CO_2 reduction, the total cost curve under a low gas price scenario will therefore rise more steeply at high levels of emission abatement, and mitigation costs—the derivative of the total cost curve—will be correspondingly greater.

Fig. 6 illustrates this phenomenon. For moderate levels of abatement, low gas prices yield less expensive CO_2 reductions as fuel switching and displacement of coal by gas plants lower overall emissions at favorable cost. The ordering of the supply curves flips for CO_2 reductions above 45 percent, with the lowest mitigation costs corresponding to the high gas price scenario. Total generating costs, however, remain uniformly lower for the 2.5$/GJ gas price scenario as the reduction in capital and O&M expenses is greater than the increase in CO_2 control costs.

From a social cost standpoint, the consequences of gas price uncertainty increase when constraints on future carbon emissions are also unknown. A return to the moderate and relatively stable gas prices of the 1990s would sustain the decade's preference for gas over coal plants. Should significant reductions in CO_2 output be required, this alternative could represent an expensive sunk investment and lock-in to a high-cost technology path. In the face of high gas prices, a coal-based CCS infrastructure could provide lower-cost abatement for greater levels of CO_2 mitigation. While the results behind this analysis are, of course, highly dependent on modeling assumptions, such possibilities highlight the need to consider how investment decisions made today might restrict mitigation options in an uncertain future.

• 2

The previous section examined the ''existing capacity versus new plant'' dynamic as a driver of electric sector CO_2 mitigation costs. There is reason, however, to think that coal plant retrofits—an intermediate approach—could be an important route to early adoption of CCS. Flue gas separation of CO_2 using an amine absorption process, for instance, is a mature technology and is similar in concept to ''add-on'' controls for sulfur dioxide (SO_2) emisof (SO

Table 3
Scenario analysis results: entry of CCS technologies plus marginal carbon price, average cost of electricity, and 2026–2030 fuel mix for 0, 50, and 75 percent emission reductions under various departures from the baseline model scenario (see the notes following the table for a definition of symbols and scenarios)

	Scenario	Baseline Model	Without CCS	5% Discount Rate	10% Discount Rate	2.50 \$/GJ Gas[a]	4.20 \$/GJ Gas[a]	45 \$/tC Sequestration[b]	15 \$/tC Sequestration[b]	+ 20 \$/tC Sequestration[c]	H_2-CGCC[d]
1st CCS (\$/tC)[e]	Coal	75	n/a	75	75	125	75	100	75	25	100
	Gas	200	n/a	200	200	175	250	225	175	150	200
	Retrofit	*	n/a	*	*	*	125	*	*	25	50
0% CO_2 reduction[f]	Ave COE (c/kWh)	2.37	2.38	2.37	2.38	2.27	2.53	2.37	2.38	2.37	2.37
	% Coal	53	53	53	50	11	57	53	53	53	53
	% Gas	19	19	19	22	62	17	19	19	19	19
	% Renewable	27	27	27	27	27	26	27	27	27	27
50% CO_2 reduction[f]	C-Price[g] (\$/tC)	83	141	79	99	140	86	109	69	21	75
	Ave COE (c/kWh)	50% CO									

as land constraints at existing coal plants, licensing and regulatory issues, and the need to modify (or design) separation technologies for a new operating environment (Herzog et al., 1997).

Data on retrofit costs and performance, however, are generally unavailable. Although utility managers are known to be exploring the option, most engineering studies remain private. Simbeck and McDonald (2001) provide one of the few thorough retrofit assessments in the public domain, and carbon capture retrofits have recently been incorporated into the Carnegie Mellon *Integrated Environmental Control Model* (IECM, 2001; Rubin et al., 2001). As noted in the baseline model discussion (Section 2), CCS retrofits of pre-existing coal plants remain uncompetitive under this set of assumptions and do not contribute to the reduction of MAAC region CO_2 emissions.

It is therefore worth estimating the range of retrofit cost and performance specifications over which the option makes economic sense. Four parameters determine the attractiveness of retrofitting the existing coal-fired generating infrastructure for CO_2 capture: the initial conversion capital cost, the associated increase in marginal operating costs, the energy penalty of the control technologies, and—related in its effects to this last factor—the efficiencies of the original coal plants. Fig. 7 presents results from a parametric analysis of the retrofit energy penalty and combined capital and operating costs. (Note that a decrease in the energy penalty is equivalent to an increase in base plant thermal efficiency in this modeling framework.)

the H_2-CGCC alternative does not significantly affect the combined share of new and retrofit/repowered CCS units. Once again, CCS is limited to baseload electricity optimization framework, the real world can show an equally strong sensitivity as demonstrated by the recent reemergence of interest in coal-fired capacity after a decade-long absence of significant new coal plant construction. The challenge is to choose optimally between coal and gas when both gas and carbon prices are uncertain.

Second, the cost of CO_2 mitigation is influenced by the initial distribution of plant technologies—for the MAAC region, a market dominated by vintage coal plants. At moderate natural gas prices, such a distribution is significantly out of equilibrium: given current prices for fuel and the operating characteristics of new plants, the generating mix would move from coal to gas—and therefore to lower CO_2 emissions—in the absence of a CO_2 constraint. This analysis illustrates how estimated CO_2 control costs are therefore lower than they would be in a system that began with installed capacity optimized for current costs and technology standards. Mitigation cost estimates, for instance, are seen to be as much as 50\$/tC lower for CO_2 reductions between 50 and 80 percent than they would be without this ''free lunch''.

Finally, the 30\$/tC sequestration cost used here is included to provide a plausible accounting of the full costs of CCS in power generation. Actual sequestration cost estimates are uncertain and site-specific. Significant uncertainties exist, for instance, concerning the physical capacity and stability of reservoirs, the regulatory environment for sequestration, the long-term costs of monitoring and verification, and the public's willingness to accept underground CO_2 injection. While these issues could lead to sequestration costs much greater than 30\$/tC, there is also the possibility that CO_2 can be sold for enhanced oil recovery or coalbed methane production. As demonstrated here, mitigation costs decrease substantially and CCS plants enter the generating mix at a very low carbon price when CO_2 has economic value.

This analysis, of course, ignores important factors that are likely to be relevant in any actual implementation of CCS. While the effect on the attractiveness of CCS as an abatement strategy, as well as on mitigation costs more generally, is difficult to predict, there is reason to be optimistic that the impact of these factors could accelerate electric sector CCS adoption.

First, this analysis ignores technological change. The cost of CCS technologies will likely decline autonomously with time, and widespread adoption of CCS would create additional cost reductions trough learning-by-doing and the attainment of economies of scale (Grubler et al., 1999). At least three factors, however, complicate the modeling of technological change: (1) cost and performance improvements will apply to conventional generation technologies and non-fossil renewables as well as CCS; (2) the inclusion of endogenous change (leaning) would require a computationally intensive non-linear model; and (3) there is no demonstrated ability to predict technological evolution. As noted in Section 2, the CCS cost estimates given here are intended to represent plants that would be operational before 2015 as part of a cumulative installed capacity of at least 5 GW in the MAAC region. CCS plants, however, are added later in most of the modeled scenarios and worldwide installed capacity would presumably be much larger. The abatement cost estimates provided here are therefore likely to be conservative.

Likewise, this analysis does not consider multi-pollutant regulation. The control of criteria pollutants, toxics, and fine particulates imposes cost and performance penalties that would influence technology choices in ways for which this analysis does not fully account. Stricter regulation of conventional pollutants, for instance, would likely accelerate coal plant retirement and favor investment in renewables, nuclear, or new gas units. Important interactions also exist between the removal of CO_2 and criteria pollutants. In general, there is little doubt that CCS will decrease emissions of SO_2 and NO_X, with amine retrofits perhaps being the sole exception (Rubin et al., 2001). Moreover, the increase in capital and operating costs due to CCS will be less for baseline plants that have stronger controls for criteria pollutants. Inclusion of such controls would lower the marginal cost of CO_2 control, and under plausible scenarios of US environmental regulation, this multi-pollutant interaction could significantly accelerate the adoption of CCS technologies.

In summary, this analysis fills an important niche between economy-wide assessments of carbon capture and sequestration and plant-level studies of CO_2 control costs. The conclusions highlight the manner in which plant dispatch, the initial distribution of generating capacity, trends in fuel prices, and the feasibility of CO_2 sequestration would influence the attractiveness of CCS should significant reductions in electric sector CO_2 emissions be required. A balanced consideration of these factors provides support for CCS and lends credence to the conclusion of top-down analyses that the availability of CCS significantly reduces overall CO_2 abatement costs (see, e.g., Edmonds et al., 1999). CCS, however, would be a disruptive technology, forcing reevaluation of the assumptions on which regulation, institutional arrangements, technology choices, and even environmental goals are based. Rigorous prediction of these broader impacts lies beyond the reach of this analysis.

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