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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

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Abstract

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 availability 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. Introduction

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 generation, for instance, depends on a large fleet of coal plants—readily identifiable point sources that burn the most carbon-intensive fossil fuel and account for a third of the nation's energy-related CO_2 emissions (EIA, 2000). Compared to distributed emission sources in the transportation sector, these plants make easy targets for CO_2 abatement as deep reductions might be achieved with minimal impact on energy infrastructures. At its point of use, electricity would "look" the same. Hence, the need to change both the means of supply and use—a coupled "chicken and egg" problem—would be avoided. It therefore seems likely that CO_2 reduction will be less expensive and action more rapid in the electric power industry than in other sectors of the economy.

Similarly, the centralized ownership and management of the electric utility industry facilitates regulation, and generators have gained considerable experience over the last three decades with increasingly tighter controls on conventional pollutants—analogues to CO_2. Moreover, with limited international trade in electricity, government action that raises prices in the electric sector would be less likely to cause movement of producers to less regulated countries than would be the case, say, for

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much of the industrial sector (Simbeck, 2001b). Owners of fossil-electric generating plants are therefore likely to be called upon to make substantial, near-term cuts in their CO_2 emissions should serious action be taken to mitigate the risk of climate change.

Atmospheric releases of CO_2, however, are not an inevitable consequence of fossil-electric power generation. Currently in use on industrial scales, the processes required to separate CO_2 from fossil fuels either before or after combustion exist as mature technologies. Furthermore, an improved understanding of relevant geological processes is increasing confidence in geological sequestration as a means of isolating CO_2 from the atmosphere on a centuries-long timescale. The integration of carbon capture and sequestration (CCS) with electricity generation may therefore provide *an additional* route to achieving significant reductions in CO_2 emissions over the next few decades.

The fundamental advantage of CCS as a CO_2 control strategy is its compatibility with today's electric power infrastructure and corresponding point sources of CO_2 emissions. New units with carbon capture, for instance, would be comparable to conventional fossil-electric plants in terms of their generating capacity, siting requirements, and availability for dispatch. CCS retrofits of existing plants—particularly the large US fleet of economically competitive coal-fired units—are also possible. Moreover, as new CCS plants would be built around familiar technologies, they could make use of existing construction techniques, managerial training, and equipment suppliers. The ability to capitalize on this end-to-end industry experience may encourage early electric sector support for CCS should significant reductions in CO_2 emissions be required (Keith and Morgan, 2001).

Emerging estimates also suggest that CCS might offer the prospect of lower electric sector CO_2 mitigation costs than alternatives such as non-fossil renewables (e.g., see Simbeck, 2001a, or the studies cited in David, 2000). In addition, the existence of niche markets and technical synergies—the ability, for example, to provide CO_2 for enhanced oil recovery or the compatibility of carbon capture with the polygeneration of synthetic fuels and electricity at refineries—may facilitate adoption of CCS technologies. The compatibility and maturity of CCS system components therefore affords the possibility of more rapid near-term CO_2 emissions abatement than might be the case if the technology was in an earlier phase of the innovation-development process.

Counterbalancing this optimism are the challenges of integrating component CCS technologies to build a complete system, as well as the technical and political uncertainties associated with CO_2 sequestration. The long-term ability of deep saline aquifers or depleted oil and gas reservoirs to contain CO_2, for instance, remains unproven. Important issues related to monitoring and verification, public perception and acceptance, and the place of CO_2 sequestration in the current regulatory regime must also be confronted before investors will risk capital on CCS projects. Moreover, environmental organizations have raised legitimate concerns that CCS—an "end of the pipe" approach to mitigating climate change—may incur significant opportunity costs, displacing resources and attention that would be better directed to the development of renewable and other sustainable energy resources (see, e.g., Hawkins, 2001).

Estimates of the extent to which CCS would lower the cost of reducing electric sector CO_2 emissions and the effective carbon price at which CO_2 capture plants would enter an actual power-generation system are also uncertain. Both depend on assumptions about the use and retirement of existing generating units, as well as competition from abatement alternatives such as advanced natural gas technologies and non-fossil renewables. In general, the cost of CO_2 mitigation via CCS will vary directly with the utilization of carbon capture plants, where the dispatch of individual plants is a function of the marginal operating costs of all available units. An examination of how CCS plants would enter and operate in an existing electric-power system is therefore required.

Consider first the need to incorporate the dynamics of plant dispatch in assessments of CO_2 mitigation costs. As new generating units are integrated into an existing power pool, and as electricity demand and factor prices change with time, the utilization of individual plants will vary. Increased use of both existing and new gas plants, for instance, will likely be the least-cost alternative for moderate reductions in CO_2 output. Gas-fired units will therefore fall to the bottom of the dispatch order and displace coal plants as carbon prices begin to rise. When the cost of carbon emissions is high enough that CCS becomes competitive, however, capital-intensive carbon capture plants would enter the generating mix with the lowest marginal operating costs and displace existing fossil-energy units. The use of conventional coal plants in particular would then decline as their operating costs increase with both the price of CO_2 emissions and the corresponding reduction in load factors. These shifts in the dispatch order affect the mitigation cost at which CCS enters, though the magnitude of this effect depends on how all available generating units interact to meet a specific demand profile when both demand and factor prices vary with time.

Consider next the need to account for existing capital. Today's electric power system is not "optimized" for the current economic, technological, and regulatory environment. In particular, vintage coal-fired plants, with little of their original capital investment left to be 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 vulnerable to gas price volatility. A modeling framework in which sunk costs matter is needed to capture these dynamics.

Finally, it is unclear whether retrofit or new CCS plants would be favored, and if the availability of retrofits would significantly increase the attractiveness of CCS as an abatement option. Conversion of existing units for carbon capture would lead to a reduction in plant output due to the energy requirements of the CO_2 separation process. The desirability of the retrofit option would be a function of this energy penalty, the base plant efficiency, and the means through which the plant derating is offset. New generating capacity, for instance, could compensate for the loss in output, or units currently reserved to meet peak demand might be dispatched more often. Understanding the role that carbon capture retrofits might play thus requires consideration of plant dispatch.

Previous studies of carbon sequestration have either included a less detailed representation of CCS technologies in economy-wide studies of CO_2 abatement (e.g., Biggs et al., 2001; Edmonds et al., 1999), or have addressed mitigation costs on an individual plant basis (e.g., David, 2000; Herzog and Vukmirovic, 1999; Simbeck, 2001a). Macroeconomic models, for instance, seek to balance production and consumption across all sectors of the economy and are typically constrained by computational requirements from including plant dispatch and a detailed characterization of existing generating capacity in their assessment of CO_2 mitigation costs (Hourcade et al., 1996). Plant-level assessments, in contrast, compare the cost of electricity for a base generation technology to figures from a similar plant with carbon capture, and then compute the carbon emissions mitigated per unit of cost. As the authors of these studies clearly note, a plant-level approach is necessarily limited to parametric consideration of sunk capital and unit dispatch (see, e.g., David, 2000). An assessment of how specific CCS generating technologies would be used in an actual electric power system is therefore required.

Incorporating these analytical needs, this assessment takes a perspective intermediate to existing studies and looks at CCS in the context of a centrally dispatched regional electric market. The analysis examines how the potential integration of CCS technologies depends on both internal factors like the natural turn-over of generating capacity and external cost drivers such as fuel prices, and assesses the impact of CCS on the cost of CO_2 control. As important as context is the timeframe under consideration. Falling between that of the Kyoto Protocol (now less than a decade) and century-long studies of global climate change, the assessment's 25–30 year perspective ensures that costs sunk in current infrastructure remain relevant and allows time for technological diffusion, but remains free of assumptions about the emergence of unidentified radical innovations.

The following section of this paper describes the modeling context in which these issues are examined. Section 3 then discusses the calculation of mitigation costs in an electric market context. The following sections build on this analytical framework, examining the effects of sunk capital and natural gas prices (Section 4) as well as coal plant retrofits and the cost of CO_2 sequestration (Section 5). The conclusion provides a summary of the analysis and discusses the likely impact of those factors that remain outside of its boundaries.

2. CCS diffusion in an electric market dispatch model

The cost of mitigating CO_2 emissions associated with a particular control technology is a function of the technology's capital requirements and operating characteristics as well as its utilization in an integrated electric supply system. Understanding the cost of CO_2 abatement via CCS therefore requires a perspective greater than that of the individual plant. While investment decisions within a power pool are increasingly made by multiple independent entities, coordination of plant dispatch remains centralized even in competitive wholesale electric markets. The domain of this assessment is accordingly that of a centrally dispatched power pool.

The analysis assumes a classical utility planning perspective in which investment decisions aim to minimize the net present value of capital and operating costs so as to meet demand over a specified planning horizon (Turvey and Anderson, 1977). Individual operators in a real electric market will seek to maximize profit, and the resulting investment pattern may not minimize the costs. This framing, however, is suitable for estimating the *social* costs of CO_2 controls.

Capacity planning is driven by twin dynamics: increasing electricity consumption and the replacement of uneconomical power plants require investment in new generating capacity, while available units must be dispatched to meet demand. These drivers are not independent; although capital investment involves a longer planning horizon than day-to-day dispatch considerations, capital recovery requires expectations of how new facilities will be used. A linear programming

Table 1
Specification of model domain and input parameters

Model domain	
Spatial aggregation	US NERC level (data are for the MAAC region—PJM-ISO)
Planning horizon	40 years (2001–2040)
Time step	5-year periods
Base case parameters	
Parameter specification	All technology parameters are independent of installed capacity
Energy demand growth	8% *per period* (70% increase over investment horizon)
Period 1 fuel prices	Coal 1.10 \$/GJ; Gas 3.20 \$/GJ; Oil 4.10 \$/GJ; Uranium 0.1 \$/GJ
Fuel price growth rate	Coal 0%; Gas 4%; Oil 0%; Uranium 0% *per period*
Carbon sequestration cost	30 \$/tC (6.8 \$/t CO_2)
Discount rate	7.5%
Implementation	
Modeling environment	Microsoft *Excel* and Mathworks *MATLAB*
Framework	Linear Programming with 7040 decision variables and 1268 constraints (solved in 1 min on a 300 MHz Pentium II)
Objective	Minimize the net present value of aggregate capital and operating costs over the planning horizon assuming "perfect foresight"

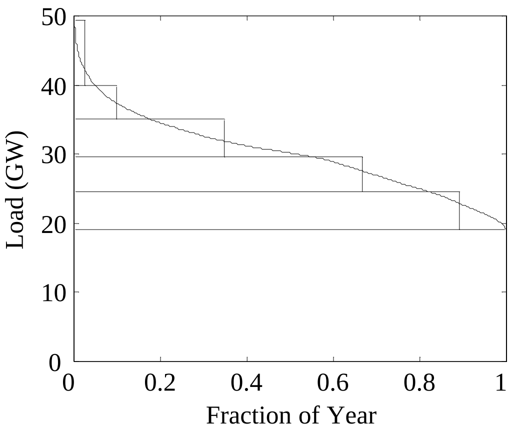

Fig. 1. Year 2000 load duration curve for the MAAC NERC region (the PJM system) and its discretized approximation. The curve represents the fraction of the year that hourly electricity demand in 2000 exceeded a given level (PJM, 2001). Explicit seasonal variation in peak and baseload levels is thus ignored. Demand growth in subsequent periods follows EIA projections (EIA, 2001a), although the shape of the load-duration curve remains constant.

(LP) model provides a sufficient framework for representing simultaneous investment and dispatch decisions.

Table 1 outlines the model domain and input parameters. The model represents a single power pool with perfectly efficient transmission, and without imports or exports of electric power. Model parameters are closely based on the Mid Atlantic Area Council (MAAC) region of the North American Electric Reliability Council (NERC), the largest integrated power pool in North America (under the centralized control of the PJM Independent System Operator). A 40-year planning horizon (2001–2040), divided into discrete 5-year periods, is examined. Note that much of the analysis focuses on the role of CCS in 2026–2030 (period 6). This time frame gives ample opportunity for CCS technologies to enter the generating mix, and is in keeping with the focus on near-term electric sector CO_2 mitigation. The model time horizon continues for an additional two periods (to 2040) in order not to conflate "end effects" with the results of interest.

Unlike top-down, macroeconomic assessments of CO_2 abatement (e.g., Biggs et al., 2001; Edmonds et al., 1999), demand and factor prices are exogenous to this analysis: given fuel prices plus cost and performance specifications for each class of generating technology, the model dispatches installed capacity to meet the six-layer discretized approximation to the MAAC load-duration curve (LDC) shown in Fig. 1. It is assumed that the LDC maintains its shape over all time periods. Note that while the model does not distinguish between winter and summer demand profiles, this construction of the LDC implicitly captures seasonal differences in peak loads.

Between 2001 and 2040 annual electricity demand increases approximately 70 percent, from 278 TWh in the first period to 476 TWh per year between 2036 and 2040. This trend is an extrapolation of MAAC projections (MAAC, 2001) and, while somewhat higher in magnitude, is also consistent with the growth rate assumed in the Reference Scenario of the US Energy Information Administration's (EIA) *Annual Energy Outlook* (EIA, 2001a). Peak loads increase from 52 to 89 GW between the first and last periods.

The same EIA scenario (EIA, 2001a) furnishes the starting point for fuel cost assumptions. The baseline price of natural gas sold to electricity generators, for instance, increases from 3.20 to 4.20\$/GJ between 2001 and 2040 (approximately 0.8 percent annually, or 4 percent per model period), while the prices of coal, oil, and uranium remain constant. Section 4 examines perturbations from these assumptions. Associated with each fuel class is a heating value (in GJ/kg-fuel) and a carbon intensity (in kg-C/kg-fuel). Note that all monetary values are in year 2000 dollars.

The analysis groups current MAAC generating capacity into one of eight fuel cycle categories: three classes of pulverized coal (PC) units, single- and combined-cycle gas turbines (GT and NGCC, respectively), oil-fired combustion turbines, plus nuclear and hydro-electric plants (Table 2). Each technology corre-

Table 2
Base model technology cost and performance parameters. CCS specifications represent what might be expected in 2015 for a cumulative CCS MAAC region installation of 5 GW.

Technology	Capital cost ($/kWe)	Variable O&M (cents/kWh)	Fixed O&M ($/kW)	Thermal efficiency (% HHV)	Base year installed capacity (GW)
PC 1	—	0.50	30.0	27	7.6
PC 2	—	0.45	30.0	30	9.3
PC 3	—	0.40	25.0	34	8.0
PC 4	1200	0.40	25.0	38	0.0
IGCC	1400	0.20	40.0	42	0.0
IGCC + CCS[a]	1900	0.35	55.0	36	0.0
GT	300	0.05	7.0	23	6.5
NGCC	450	0.05	15.0	50	1.7
NGCC + CCS[a]	900	0.15	25.0	45	0.0
Oil[b]	—	0.05	7.0	20	6.4
Nuclear[b]	—	0.40	57.0	30	13.7
Hydroelectric[b]	—	0.00	25.0	—	2.3
Wind[c]	1500	0.80	15.0	—	0.0
PC 1-Retrofit	700	0.80	65.0	22	0.0
PC 2-Retrofit	625	0.75	65.0	24	0.0
PC 3-Retrofit	550	0.70	60.0	27	0.0
PC 4-Retrofit	500	0.70	60.0	30	0.0

[a] All CCS plant O&M figures include the cost of compressing CO_2 to a suitable pressure for transport (approximately 100 atm).
[b] The model excludes the addition of new oil, nuclear, and hydro-electric capacity.
[c] See the text for a description of wind specifications.
PC—pulverized coal, IGCC—integrated coal gasification combined-cycle, GT—single-cycle gas turbine, NGCC—combined-cycle gas turbine; O&M—operating and maintenance costs; CCS—carbon capture and sequestration; HHV—higher hearing value. Figures are derived from Beamon and Leckey (1999), David (2000), EIA (1999, 2001a, b), EPA, 2001), IECM (2001), MAAC (2001), McGowan and Connors (2000), Simbeck (2001a,2001), and Simbeck and McDonald (2001).

sponds to a pre-existing vintage except for coal units, 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 technologies—including state-of-the-art PC and integrated (coal) gasification combined-cycle (IGCC) plants, both IGCC and NGCC plants with carbon capture, as well as wind turbines—are available only as new capacity. CCS retrofits of the three "old" coal plant categories are also investment options.

New capacity added in each of the eight time periods plus the pre-existing plants therefore yield a total of nine plant vintages for the individual generating plant categories (except hydro-electric and nuclear, as discussed below). It is important to note once again that the model does not "see" individual plants, only aggregate capacity associated with a particular vintage and fuel-cycle category (e.g., wind capacity added in period 3 or pre-existing single-cycle gas turbines). "Plants" or "units" as used here therefore refer to the addition or dispatch of a flexible portion of this capacity.

Associated with each class and vintage of plant is a cost of new capital, a fixed operating and maintenance cost (FOM), a non-fuel variable operating cost (VOM), and a thermal efficiency. Table 2 summarizes these parameters, which are typical of existing US electric power plants and are in line with the historical findings in Beamon and Leckey (1999) as well as the assumptions used by the EIA (EIA, 2001b). Minor adjustments improved the fit between model output and projections for the MAAC region (EIA, 2001a; MAAC, 2001). To reflect the lack of experience with newer generating technologies and therefore avoid unrealistic single-period additions of new capacity, the model also includes a rate-of-growth cap on gas, wind, and CCS units.

CCS plant costs and performance specifications, of course, are difficult to specify. The literature reports estimates that vary from highly optimistic (e.g., Nawaz and Ruby, 2001) to conservative (see, for example, the studies reviewed in David, 2000). The real uncertainty, however, is probably less than the range of cited estimates as different assessments employ dissimilar baselines and make widely different assumptions about when CCS technology will be ready (Keith and Morgan, 2001). The cost and performance specifications used here are based on both academic and industry assessments (e.g., David, 2000; Simbeck, 2001a), and reflect the authors' judgment about what might be expected around 2015 for a cumulative CCS installation of 5 GW in the MAAC region. These estimates are therefore conservative for the entire 2001–2040 timeframe, especially when one considers the learning-by-doing and economy-of-scale cost reductions that would accompany 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 15 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 sequestration. The actual cost of CO_2 sequestration would be site-specific, subject to significant regulatory uncertainties, and likely to increase as more economic sequestration sites reach capacity.

Sequestration costs may be negative, however, where CO_2 can be used for CO_2-enhanced oil and gas recovery or enhanced coal bed methane production (ECBM). Within and immediately to the west of the MAAC region, for instance, lie the Northern Appalachian coal beds (with significant gas resources), as well as the smaller Pennsylvania Anthracite fields located near the region's center (see, e.g., Milici, 2001). A significant fraction of the coal-fired generating capacity in the MAAC region either overlies or is within 300 km of these coal fields. While the potential for ECBM has not been seriously assessed for this region, it seems likely that it is significant and that with gas prices of 4$/GJ and higher ECBM might be able to pay as much as 0.5$/Mcf for CO_2 (approximately 35$/tC) (Wong et al., 2000). As a reference, CO_2-enhanced oil recovery operations in the Permian basin and elsewhere in North America routinely run pipelines for hundreds of kilometers, and are profitable with CO_2 costs over 1$/Mcf. Conversely, more pessimistic assessments of CO_2 sequestration in aquifers suggest that costs could exceed 50$/tC. A sequestration cost of 30$/tC is a reasonable estimate, while actual values might range from –25$/tC near ECBM sites to near +50$/tC on the Atlantic Coast.

Finally, the baseline model includes three non-fossil generating technologies: nuclear, hydro-electric, and wind. The first two enter only as existing capacity. Because of their questionable social acceptability, the analysis assumes that no new nuclear or hydro plants will be installed over the investment horizon; neither, however, is forcefully retired. Wind generation therefore provides the only new source of non-fossil energy in the model.

Capital and operating costs for wind turbines are derived from McGowan and Connors (2000) and EIA modeling assumptions (EIA, 2001b). The analysis takes into account the limited MAAC region wind resources by restricting wind generation to 25 percent of its installed capacity—a capacity factor corresponding to a wind class of IV (see McGowan and Connors (2000) for a discussion of the relationship between wind class and availability for dispatch). Wind farms in the Great Plains and other areas of the US would likely supply power to MAAC if demand for this renewable source of electricity became substantial, with those regions' greater wind resources and, hence, lower-cost power output partially offsetting the expense of long-distance transmission. In ignoring transmission costs, the analysis is friendly to wind. Note, however, that the model also ignores important issues related to power back-up and storage. The cost and performance specifications are similar to what wind generation "looks like" in a more inclusive analysis (e.g., DeCarolis and Keith, 2002), though the model dispatches wind capacity without explicit consideration of these factors. In a sense, wind serves as the model's proxy renewable energy source.

Figs. 2 and 3 illustrate the performance of the model in its baseline configuration. A look at the manner in which the model achieves CO_2 reductions provides a useful starting point for subsequent analysis. Fuel switching from coal to gas, for instance, occurs for moderate carbon prices, though the model returns to coal for baseload generation as the cost of emissions increases. New coal units with carbon capture become competitive near 75$/tC, though the option of retrofitting existing coal-fired capacity for post-combustion carbon capture—which Section 5 examines in more detail—is uncompetitive below 300$/tC. Note that the availability of CCS units does not lead to an earlier turnover of conventional coal capacity. As illustrated in Section 4, however, the balance between fuel-switching and CCS as mitigation alternatives is dependent on the price of natural gas.

In comparison to coal-fired capacity, gas plants with carbon capture do not enter the generating mix until the price of carbon emissions exceeds 175$/tC. More efficient (non-CCS) gas units, used primarily to meet intermediate and peak demand, are penalized less than baseload conventional coal as the cost of emissions increases. Moreover, with fewer hours over which to spread capital costs, CCS technologies only supply peak electricity loads when very high levels of abatement are demanded.

Stepping back from the details, two processes are visible in these results. First, the pattern of entry for separate carbon capture technologies is typical of

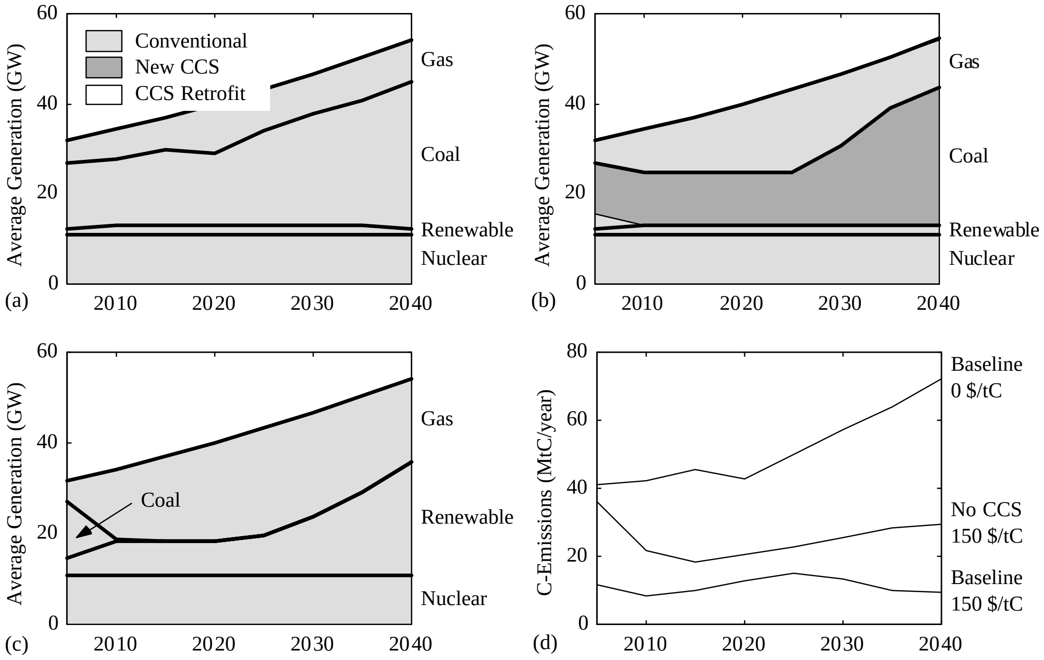

Fig. 2. Time dynamics. The first three panels (a–c) compare the fuel mix used to meet demand over the eight-period investment horizon in the absence of a price on CO_2 emissions (panel a), as well as under a 150$/tC carbon price when CCS technologies are and are not available (panels b and c, respectively). In each plot the heavy lines separate fuels, while the shading denotes CCS technology as indicated in the key for panel a. Panel d shows the carbon emission profile as a function of time for the three scenarios.

dispatch dynamics more generally: high capital, low 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.

3. Estimating CO_2 mitigation costs and the importance of unit dispatch

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-

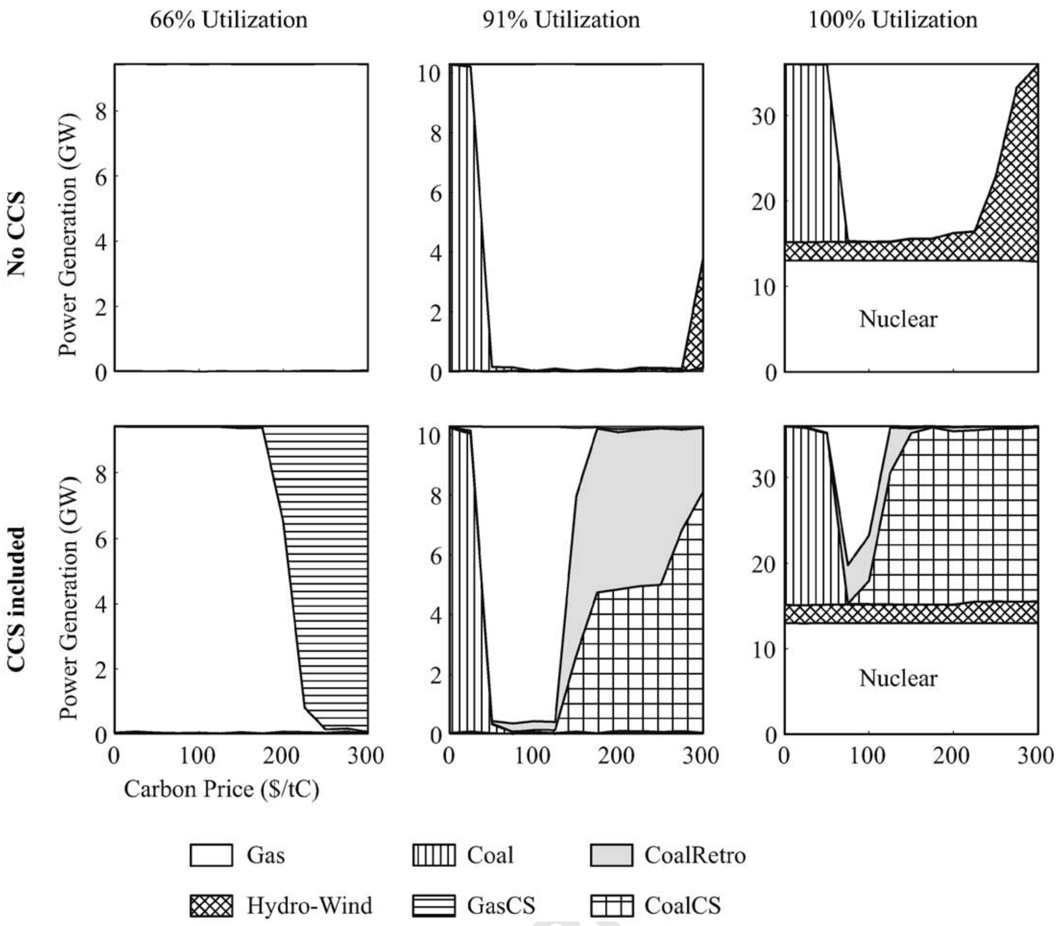

Fig. 3. Plant utilization versus carbon price. The top row shows results without CCS while the bottom includes all model technologies. The columns correspond to the lowest three levels of the load-duration curve (Fig. 1), with base load (100 percent utilization) on the far right and intermediate shoulder loads in the center and on the left (91 and 66 percent, respectively). "100 percent utilization" does not imply that individual units are dispatched 100 percent of the time; plant availability is restricted so that excess capacity is required to meet demand. Note that in the lower row the fossil portions of the base and shoulder loads switch from coal to gas and back to coal with CCS as the carbon price increases. Nuclear power only supplies base load in both cases, as indicated.

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 percent. Second, for a given reduction in CO_2 emissions, the extent to which CCS lowers the cost of abatement corresponds to the difference between the "CCS" and "No CCS" curves. Without new nuclear or hydroelectric capacity and with constrained wind resources, this decrease in mitigation costs is significant. And last, note that the "No CCS" case moves toward zero emissions only at high cost as wind generation—the model's "green" backstop technology—becomes eco-

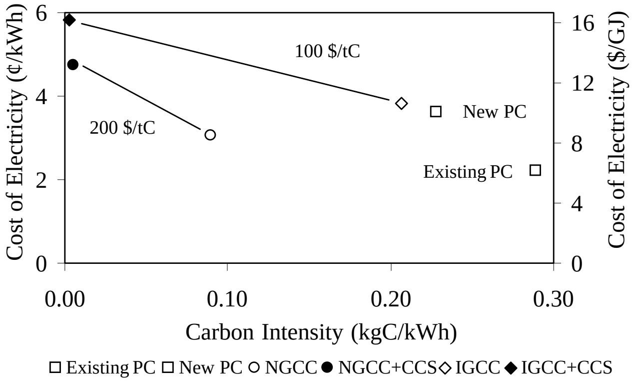

Fig. 4. Total cost of electricity versus carbon emissions per unit of energy generated. Total cost is defined as the sum of marginal and fixed operating expenses and a capital recovery charge. (Existing PC is assumed to be fully amortized and therefore does not include the latter.) The slope of the line 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 reaches 100$/tC, beyond which carbon capture dominates. Likewise, carbon capture for new gas facilities is not economical until the carbon price approaches 200$/tC. A load factor of 90 percent is assumed for all technologies; fuel prices and technology specifications are that of the unconstrained carbon emission base model (see Tables 1 and 2). ("Existing PC"—average existing amortized pulverized coal plant; "New PC"—new conventional pulverized coal plant; "IGCC"—integrated gasified (coal) combined cycle; "NGCC"—combined cycle natural gas turbine; "+CCS"—with carbon capture and sequestration.)

nomically competitive. Taken together, these features 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.

4. Natural gas prices, sunk capital, and 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.

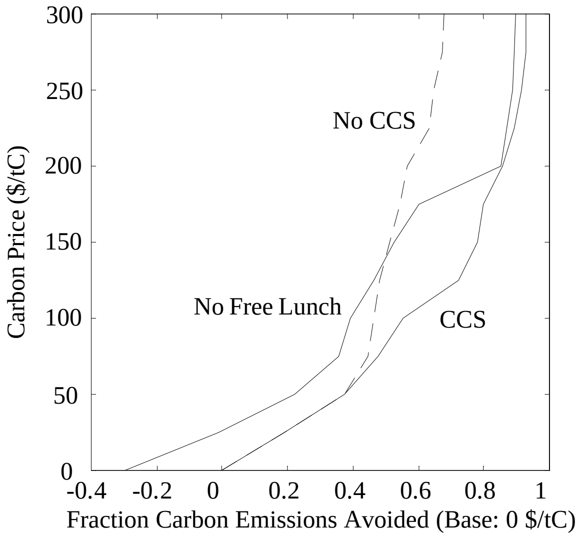

Fig. 5. Carbon mitigation cost curves when CCS technologies are available ("CCS") and when they are not ("No CCS"), as well as when the free lunch CO_2 reduction of fuel switching is removed ("No Free Lunch"). The mitigation cost curves represent a series of model runs, with carbon prices increasing from 0 to 300$/tC in 10$/tC increments. The discrete points on the curve reflect the reduction in 2001–2040 emissions under a given carbon price and 0$/tC, expressed as a fraction of the latter (2.07 GtC). This approach to generating a mitigation supply curve is equivalent to imposing a constraint on CO_2 emissions and plotting the increase in undiscounted total costs as a function of the corresponding emissions reduction. Note that the zero-carbon price emissions level of the baseline run (2.07 GtC) provides the basis used to calculate the fraction of CO_2 avoided for the "No Free Lunch" scenario.

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

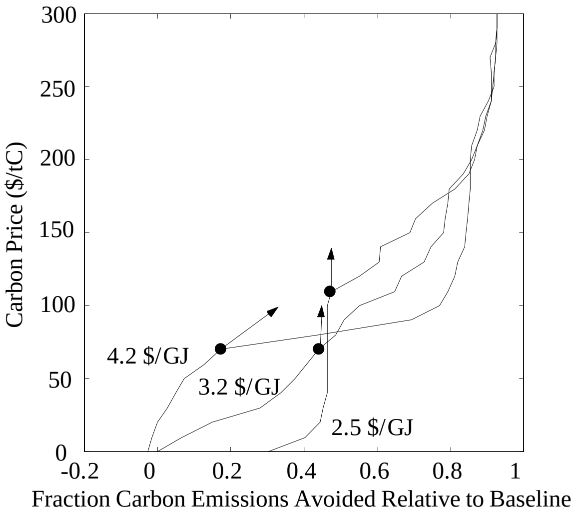

Fig. 6. CO_2 mitigation supply curves for alternative gas price scenarios. Note that the zero-carbon price emissions level of the 3.2$/GJ baseline run (2.07 GtC) provides the basis used to calculate the fraction of CO_2 avoided for all three scenarios. The horizontal distance between the 2.5 and 3.2$/GJ curves at 0$/tC therefore estimates the extent to which lower gas prices alone reduce emissions. Gas prices begin at the indicated levels and increase at the baseline 4 percent per-period growth rate. The dots mark the entry of CCS technologies and thus the point at which the CCS and no-CCS curves diverge. The arrows show the first five segments (10$/tC carbon price increments) of the non-CCS case. See Fig. 5 for details concerning figure calculations.

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.

5. Carbon capture retrofits and the cost of CO_2 sequestration

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) emissions; construction expertise and management experience would likely transfer from one control system to the other. More fundamentally, a cost-effective retrofit option would extend the useful life of existing coal plants in a world with constraints on carbon emissions. This compatibility with the economics and timing of infrastructure turn-over could lower electric sector CO_2 abatement costs. Tempering this

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] ($/tC)	83	141	79	99	140	86	109	69	21	75
	Ave COE (c/kWh)	3.30	3.78	3.24	3.42	3.48	3.63	3.52	3.14	2.61	3.20
	% Retrofit	0	n/a	0	0	0	1	0	0	20	1
	% CCS	1	n/a	2	0	17	22	2	6	33	1
	% Coal	1	0	2	0	17	44	2	9	41	1
	% Gas	71	70	70	72	56	29	71	64	32	72
	% Renewable	27	30	28	27	28	28	28	28	27	27
75% CO_2 reduction[f]	C-Price[g] ($/tC)	137	#	120	163	187	99	165	109	49	178
	Ave COE (c/kWh)	3.67	#	3.47	3.89	3.69	3.72	3.90	3.42	2.83	3.75
	% Retrofit	0	n/a	0	1	0	1	0	0	22	32
	% CCS	33	n/a	33	35	44	44	30	35	52	46
	% Coal	33	#	33	35	26	46	30	35	52	45
	% Gas	39	#	39	37	46	26	43	38	20	27
	% Renewable	28	#	28	28	28	28	28	27	27	28

[a] Period 1 (2001–2005) gas prices; prices increase at baseline 4% per period rate.

[b] Cost of CO_2 sequestration, including transportation.

[c] An unlimited amount of CO_2 may be sold for a market price of 20 $/tC.

[d] Alternate pre-combustion CCS retrofit of existing coal plants to a hydrogen-fired coal gasification combined cycle (H_2-CGCC) that leaves intact only the original coal-handling and substation equipment (Simbeck, 2001b).

[e] "1st CCS" is the mitigation cost (in $/tC) at which the generation from a particular CCS technology exceeds an annual average of 1 GW.

[f] Percent electricity generation by technology/fuel given for period 6 (2026–2030).

[g] *Marginal* cost of carbon emissions.

n/a—not applicable ("Without CCS" scenarios).

*Technology does not enter the generating mix below a 300 $/tC mitigation cost.

#A 75 percent emission reduction is not achieved for scenario below 300 $/tC.

optimism are the energy requirements of the capture process and subsequent derating of plant output, as well 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.)

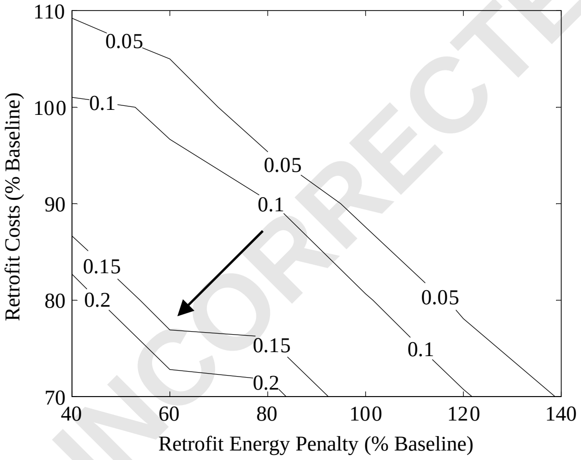

Fig. 7. Fraction of electricity produced in period 6 (2026–2030) by retrofit coal plants as a function of retrofit costs and energy penalty under a 150$/tC emissions price. Costs include capital plus fixed and variable O&M, and both sets of model parameters are shown as a percentage of their baseline specifications (see Table 2). Note that lower emission prices decrease coal plant conversions (as with CCS in general), while higher prices do not increase the share of retrofit generated power. The arrow indicates the direction of increasing retrofit penetration.

The first point to note from this analysis is that even radical improvements in the baseline retrofit energy penalty (i.e., halving the penalty to 10 percent) alone do not increase the share of electricity generated by modified coal plants to more than 10 percent. Only when the energy penalty and retrofit costs both decrease do retrofits play a role in CO_2 abatement, contributing roughly a quarter of generated electricity (Fig. 7). In addition, the ability to retrofit coal plants for post-combustion CO_2 capture does not significantly affect the combined share of all CCS units. Halving the retrofit energy penalty and achieving significant cost reductions, for instance, doubles retrofit electricity production, but does not substantially increase the approximately 40 percent baseline model CCS share of power generation (IGCC capture units simply play a diminished role). As a result, retrofit improvements have little effect on overall mitigation costs. CCS in general is limited to reducing baseload CO_2 emissions until further abatement requires cuts in the emissions of plants supplying peak loads. The lower utilization of units supplying electricity at higher levels of the dispatch order, however, makes it more difficult to recover capital investment, increasing the average cost of electricity as well as the cost of CO_2 control.

Post-combustion CO_2 capture via flue gas scrubbing, however, is not the only near-term route to CCS available to coal plant operators. Conversion to a hydrogen-fired coal gasification combined cycle plant (H_2-CGCC)—a repowering option that leaves intact only the original coal-handling and substation equipment—is also possible (Simbeck, 2001b). (Oxygen-fired coal plant retrofits are an additional possibility, but are not considered here.) This repowering option, which would incur estimated capital costs on the order of 1500$/kW (net) as industry experience with gasification technology increases, does not share the capacity derating that is a primary disadvantage of flue-gas scrubbing retrofits. In addition, a repowered H_2-CGCC plant would have a smaller footprint than the original boiler and steam turbine, thus avoiding the space constraint problems of "add-on" retrofits. Unfamiliarity with gasification technologies in the utility industry appears to be the major hurdle confronting this alternative (an argument, of course, to which flue-gas scrubbing is not immune; see Simbeck, 2001b).

Modeled as an IGCC plant with a 1500$/kW capital cost, the improved economic performance of the H_2-CGCC option increases dependence on coal plant conversion. Repowered coal plants now become competitive as a mitigation option at 75$/tC and comprise a substantially larger share of the generating mix at higher carbon prices (see the "H_2-CGCC" scenario of Table 3). This difference highlights the extent to which the amine retrofit plant derating discourages coal plant conversion. But like post-combustion retrofit schemes, adoption of 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 generation for all but the highest levels of CO_2 mitigation.

Table 3 summarizes this look at coal plant retrofits, combining its results with those from the gas price scenarios discussed in Section 4 as well as a parametric analysis of discount rates and the cost of CO_2 sequestration. The latter deserves particular attention. Actual sequestration cost estimates must take into account a variety of non-technical considerations and are site-specific (Herzog et al., 1997). 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 the baseline model's 30$/tC, CO_2 may also be sold for enhanced oil recovery or enhanced coalbed methane extraction. Where feasible, such uses could supply important and early niche markets for CO_2 produced by fossil-electric power plants, thereby encouraging development of CCS technologies. Subsequent experience-related cost reductions and performance improvements would then encourage longer-term industry adoption of CCS.

Fig. 8 and Table 3 illustrate how baseline model performance varies with sequestration cost, including a scenario in which an unlimited amount of CO_2 may be sold for 20$/tC. Mitigation costs are most sensitive to sequestration price for emission reductions above 40 percent (near the point at which CCS units enter the generation mix), although they converge as capture technology costs dominate sequestration expenses for abatement levels above 90 percent. When CO_2 has economic value, however, CCS enters the generating mix without the inducement of an emissions price and overall mitigation costs decrease substantially. While current demand for CO_2 in the eastern US is minor and sequestration costs are likely to be near the baseline level, this is not the case in oil-producing regions like Texas where the ability to capture and sell CO_2 could fundamentally alter the economics of near-term electric sector emissions abatement.

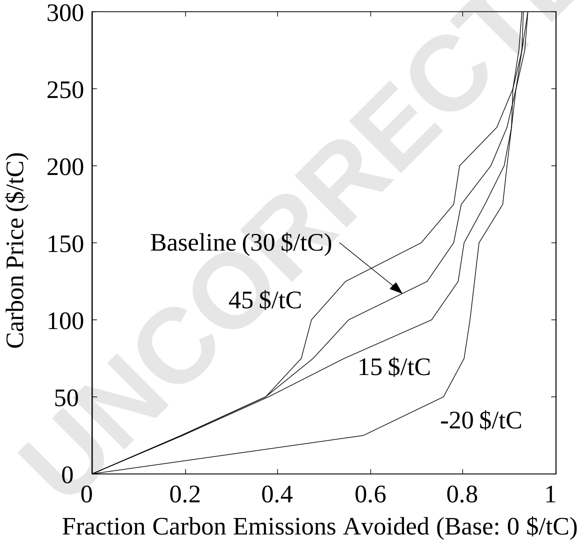

Fig. 8. The cost of carbon mitigation as a function of CO_2 sequestration cost. The "−20$/tC" curve reflects a scenario in which an unlimited amount of CO_2 may be sold for 20$/tC; all other curves treat sequestration as an expense. See Fig. 5 for details concerning figure calculations.

6. Conclusions

This analysis demonstrates that even under conservative assumptions regarding its costs and performance, CCS can significantly lower the cost of mitigating CO_2 emissions in a centrally dispatched electric market. Moreover, the analysis points to the ways in which the cost of CO_2 control depends on more general electric sector dynamics. CCS units, for instance, enter the generating mix at an emissions price around 75$/tC, after increased reliance on natural gas and dispatch reordering have cut emissions nearly in half. New coal CCS plants then dominate gas CCS units under most scenarios, with the latter becoming important only when gas prices fall to 2.5$/GJ, or when very high levels of CO_2 abatement (i.e., greater than 80 percent) force significant cuts in emissions from plants dispatched to meet short-duration peak loads.

The findings highlight three key factors that control the role of CCS in a carbon-constrained electricity market: natural gas prices, the initial distribution of generating capacity, and the cost of carbon sequestration. The remainder of this section reviews these factors and then considers how issues that were ignored in the analysis might impact the adoption of CCS technologies.

First, the manner in which CO_2 abatement is achieved and the carbon price at which CCS becomes competitive depend on the cost of natural gas. For gas prices around the baseline 3.2$/GJ, increased use of gas turbines and carbon-ordered dispatch reduce emissions up to 40 percent, and CCS does not enter the generating mix until carbon prices exceed 75$/tC. Higher gas prices produce different behavior. Coal plants with CO_2 capture, for example, enter at an emissions reduction close to 30 percent when gas is near 4.2$/GJ. At gas prices within the range prevailing throughout much of the 1990s (i.e., around 2.5$/GJ), however, conventional and CCS gas units provide the dominant means of controlling CO_2 emissions. While this sensitivity to gas prices is partially an artifact of the underlying 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.

7. Uncited references

Holloway, 2001; Howes and Fainberg, 1991.

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