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The long-term life cycle private and external costs of high coal usage in the US

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Abstract

Using four times as much coal in 2050 for electricity production need not degrade air quality or increase greenhouse gas emissions. Current SO_x and NO_x emissions from the power sector could be reduced from 12 to less than 1 and from 5 to 2 million tons annually, respectively, using advanced technology. While direct CO_2 emissions from new power plants could be reduced by over 87%, life cycle emissions could increase by over 25% due to the additional coal that is required to be mined and transported to compensate for the energy penalty of the carbon capture and storage technology. Strict environmental controls push capital costs of pulverized coal (PC) and integrated coal gasification combined cycle (IGCC) plants to \$1500–1700/kW and \$1600–2000/kW, respectively. Adding carbon capture and storage (CCS) increases costs to \$2400–2700/kW and \$2100–3000/kW (2005 dollars), respectively. Adding CCS reduces the 40–43% efficiency of the ultra-supercritical PC plant to 31–34%; adding CCS reduces the 32–38% efficiency of the GE IGCC plant to 27–33%. For IGCC, PC, and natural gas combined cycle (NGCC) plants, the carbon dioxide tax would have to be \$53, \$74, and \$61, respectively, to make electricity from a plant with CCS cheaper. Capturing and storing 90% of the CO_2 emissions increases life cycle costs from 5.4 to 11.6 cents/kWh. This analysis shows that 90% CCS removal efficiency, although being a large improvement over current electricity generation emissions, results in life cycle emissions that are large enough that additional effort is required to achieve significant economy-wide reductions in the US for this large increase in electricity generation using either coal or natural gas.

Keywords: Coal; Life cycle; Electricity

1. Introduction

This analysis models the life cycle implications of a high coal use future. The only hydrocarbon fuel in which the US has hundreds of years of reserves at current extraction costs is coal. More than 50% of electricity is generated from coal, approximately 23% of the total energy consumed in the US (Energy Information Administration, 2005a). While many future energy scenarios are possible, coal is likely to play a large role for at least the next half-century, barring significant technological changes and large hydrocarbon discoveries. Coal is attractive not only because it is economically competitive, but also because advanced generation technologies can decrease air pollution and CO_2 emissions (through carbon capture and storage—CCS) significantly from the generation phase.

We define six 2050 electricity scenarios that explore interesting assumptions about future fuel and technology choice as well as different prices, emission factors, and efficiencies. Two scenarios employ natural gas combined cycle (NGCC) technologies, while four scenarios investigate pulverized coal (PC) and integrated coal gasification combined cycle (IGCC) technologies, with and without CCS. We do not predict that any of these scenarios will occur, but rather we use the scenarios to explore the cost and environmental implications if each scenario did occur.

The characteristics of future electricity generation technologies are taken from the IECM software (IECM-cs v.5.1.3, 2006). This DOE software gives the best current description of the cost, efficiency, and emissions of

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advanced coal and natural gas technologies. While additional technological advances could occur between now and 2050, these capital investments have such long lifetimes that we consider these estimates to be conservative but realistic.

Several previous studies use a range of assumptions in comparing the technical, economic, and environmental differences between PC and IGCC systems (Rubin et al., 2005; Booras and Holt, 2004; Braine et al., 2005). For example, American Electric Power analyzed the best technology for a new plant in the Ohio region and the Electric Power Research Institute assessed the costs associated with retrofitting an IGCC (GE gasifier) facility for CCS (Holt et al., 2004; Rutowski et al., 2003). Reinelt et al. (2007) investigated options for an existing coal-fired power plant which include continued operation of the plant, the replacement of the plant with PC, or with IGCC, with and without CCS.

2. Scenarios

Forecasting future energy demand and availability accurately is impossible. Instead, future scenarios can aid in thinking about future realities by building a framework for evaluating the consequences of potential actions (Craig et al., 2002). The focus of this analysis is the system implications of greatly increased coal usage in the US. The scenarios extend to 2050. However, vastly greater coal use could occur earlier.

The US annually consumes 1.1 billion tons of coal to generate about 2 trillion kWh from coal (50% of the 4 trillion kWh generated total). Our scenarios begin with the Energy Information Administration (EIA) projections in the Annual Energy Outlook (AEO) (EIA, 2005b). The EIA base case assumes an electricity demand growth of 2% annually through 2025. We extrapolate from 2025 to 2050 by assuming a growth rate in electricity demand of 2% per year. This results in a total electricity demand of 10 trillion kWh per year in 2050. We specify these scenarios to explore the life cycle cost and environmental impacts of quadrupling coal use. We choose a 2050 time frame so that all new generation will be built with the best available technologies. This level of control far exceeds that required to meet current New Source Performance Standards (NSPS).

Generation cost is calculated using a 30-year lifetime and discount rate of 8% per year; the price of coal is based on current free on board prices (broken down by coal type shown in Table 2). The capital and operating costs of CCS are based on an amine scrubber for the PC and NGCC plants and a Selexol process for the gasification plants. The separated CO_2 is transported by pipeline with deep underground injection; the capital and operating cost is assumed to be \$10/ton of CO_2. The amine scrubber and Selexol process are assumed to remove 90% of the CO_2. Plant costs and emissions are calculated by the Integrated Environmental Control Model (IECM-cs v.5.1.3, 2006) for generation; emissions for the rest of the life cycle are calculated in the Economic Input–Output Life Cycle Assessment (EIOLCA) software (Carnegie Mellon Green Design Initiative, 2005). The emissions from the mining and transportation phases are calculated using a process-based approach from current emissions (EPA, 2003). Current mining emissions were divided by 1.1 billion tons of coal that were mined in that year and then multiplied by the total coal required for each scenario in order to obtain the total emissions for each scenario. Current rail transportation emissions were divided by current total ton-miles of transport. The ton-miles for each scenario were calculated by the proportion of coal consumed and the average distance that these coal types are transported (EIA, 2004).

The infrastructure required for these scenarios assumes that it will be built in addition to currently existing infrastructure in the US. New rail, barge, and truck capacity is required to transport the coal, new mines need to be developed, and new pipelines are required to transport the natural gas once it has been extracted. We include the cost of the infrastructure, but not the potential issues associated with siting the infrastructure in this analysis. Siting new infrastructure, particularly new rail and transmission lines, may be the most difficult part of these scenarios.

For all scenarios the social costs of the pollution are internalized by values based on their social costs (estimated by Matthews and Lave, 2000) and the current market price of an emissions allowance: \$900/ton for SO_2, \$2600/ton for NO_x; and \$2800/ton for PM. The valuation of CO_2 emissions was investigated parametrically and is shown in Fig. 4.

Table 1 summarizes the technologies that are the basis of the scenarios and each scenario is discussed in more detail below.

Scenarios 1a and b produce 80% of the 10 trillion kWh of electricity from natural gas using combined cycle units. These scenarios are considered the most environmentally benign set of fossil scenarios and are the baseline for comparison with the coal scenarios. While the future of natural gas prices is difficult to forecast, we assume a price of \$7.0/MMBtu. The effect of different gas prices is investigated in Fig. 8. All fuel costs remain constant over time. The well-head natural gas price in the US averaged \$7.50/MCF in 2005, according to the EIA. Total US usage of natural gas was 22 trillion cubic feet (TCF), of which 27% was for electricity generation. If 8 trillion kWh were produced from natural gas, 49 (57 with CCS) TCF would be required for electricity generation. Since this results in almost tripling total demand and increasing the amount used for electricity generation by about a factor of 10, we think it likely that natural gas prices would rise significantly.

The capital costs (in 2005 dollars) of the basic PC and IGCC plants are \$1500–1700/kW and \$1600–2000/kW, respectively. Adding CCS would increase the cost of the

Table 1
Summary of electricity generation technologies

	Technology	Control technologies				Efficiency (HHV) (%)	Private cost (cents/kWh)		
		CO_2	SO_2	NO_x	PM		Capital	O&M	Total cost
1a. Natural gas	Combined cycle	–	–	SCR—95% efficient	–	50	0.91	4.2	5.2
1b. Natural gas + CCS		Amine system—90% efficient				43	1.9	5.0	6.9
2a. Pulverized coal	Ultra-supercritical tangential boiler	–	Wet FGD or lime spray dryer—98% efficient	SCR—95% efficient	ESP or fabric filter	42	2.1	1.6	3.7
2b. Pulverized coal + CCS		Amine system—90% efficient				33	4.2	4.0	8.2
3a. Gasified coal	GE integrated coal gasification combined cycle	–	Selexol unit—98% efficient	–	Part of raw gas cleanup	34	2.6	1.8	4.4
3b. Gasified coal + CCS		Water gas shift and selexol—90% efficient				28	3.7	3.4	7.1

FGD—flue gas desulfurization, SCR—selective catalytic reduction, ESP—electrostatic precipitator.
Source: IECM.

Table 2
Production of different coal types in the US, 2003 (EIA, 2003a)

	Bituminous	Sub-bituminous	Lignite	Total
Coal consumed (million tons)	518	431	76	1025
Coal produced (%)	51	42	7	
Price of coal ($/ton)	49	11	11	

two systems to $2400–2700/kW and $2100–3000/kW, respectively. The efficiency of 40–43% of the PC plant is reduced to 31–34% when the CCS unit is attached. The efficiency of 32–38% of the IGCC plant is reduced to 27–33% when the CCS unit is attached. The efficiencies depend on the type of coal used; they are appreciably lower for lignite.

A 90% removal efficiency of the capture units is assumed for each CCS scenario. However, the net reduction is less since there is an energy penalty associated with running the system (e.g., 90% removal per unit of electricity produced would require closer to 95% reduction per unit of coal processed).

The current mix of coal types consumed in the US is summarized in Table 2 and extrapolated to 2050. Extraction costs, sulfur content, transport costs, environmental regulations, and generation technology can change the mix of coal types used over time. The effects of a change are discussed in Section 5.

Rather than holding coal use constant, we fix output at 8 trillion kWh and assume the coal type usage mix shown in Table 2. The PC technology requires 3.1 billion tons of coal, increasing to 4.0 billion tons with CCS (2.7 and 3.5 times the current consumption, respectively). The integrated gasification combined cycle (IGCC) system requires 4 billion tons, increasing to 4.8 billion tons with CCS (3.5 and 4.2 times the current consumption, respectively).

A final set of scenarios explores the effect of moving the generation facilities to the mouth of the coal source. These minemouth plants do not require the rail infrastructure but do require additional transmission capacity.

3. Economic results

In each of the scenarios, Fig. 1 shows the system costs calculated by estimating the total capital investment required for all life cycle stages (including extraction, transport, generation, and transmission infrastructure costs), annualizing that cost and adding it to the estimated operation and maintenance and fuel costs. The monetized social cost of the emitted pollutants is added to the system costs. Finally, the social costs associated with fatalities occurring throughout the life cycle were estimated and added to the system cost. The dominant category of fatalities is from deaths during rail transport. The social costs of CO_2 emissions were not included in this figure but are considered separately in Fig. 4: there is no agreed upon value to represent the social cost of the impacts that these emissions might cause.

Life cycle wholesale electricity costs range from over 5.4 cents/kWh for the PC scenario without CCS to almost 12 cents/kWh for the scenarios with CCS. If CO_2 emissions were valued at $74/ton for PC w/CCS and $53/ton for IGCC w/CCS scenarios, the cost of electricity would be the same with and without CCS. CCS increases total costs by 40–60% due to increased capital and operating costs. Among the non-CCS scenarios, the natural gas price would

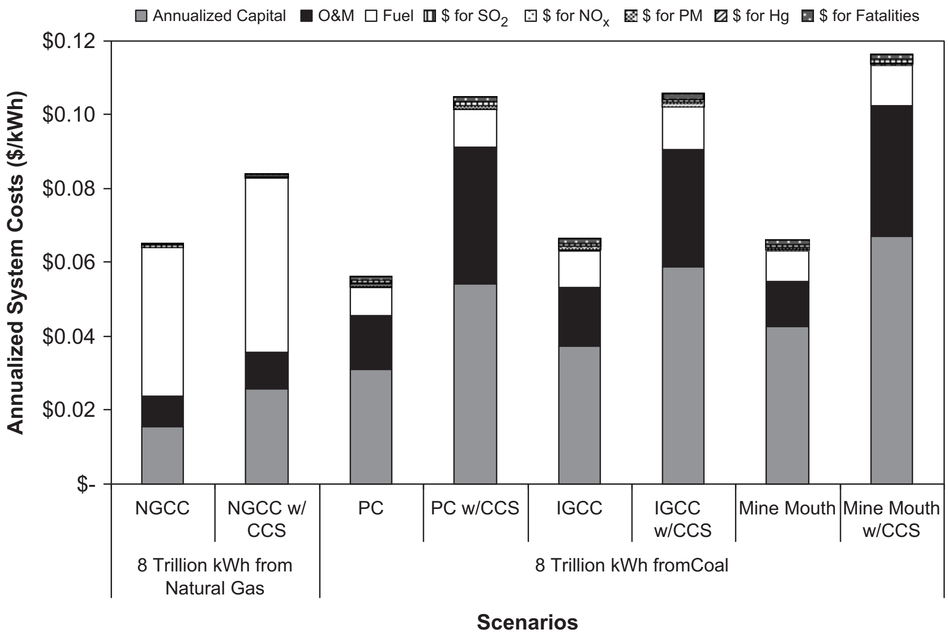

Fig. 1. Total annualized life cycle costs for coal and natural gas scenarios. CO_2 was not 'valued' in this analysis but is evaluated in Section 4.2.

have to be less than $4/MMBtu to compete with a PC plant.

The price of natural gas is assumed to be $7/MMBtu in the figure; the futures market for natural gas does not indicate increasing prices in the next few years. If natural gas prices stay at $7/MMBtu, the cheapest way of generating electricity from fossil fuels with carbon capture and storage will be NGCC with CCS. The price of natural gas would have to be at least $9/MMBtu for the coal plants with CCS to be cheaper than the NGCC plants with CCS (see Fig. 8). However, building many NGCC plants with CCS would increase the demand for natural gas, driving up the price. Thus, depending on the supply and demand for natural gas for markets other than electricity, the cheapest solution might include a few NGCC plants with CCS.

The minemouth generation scenarios show that moving the plants closer to the fuel source reduces the cost of the rail infrastructure (which is more expensive to build than the transmission system) but that this advantage is offset by the fact that there are fewer economies of scale with the transmission system. That is, while the rail system is more expensive to build, more coal can be shipped on the lines while loading the transmission lines increases energy loss and therefore requires additional transmission lines to carry the large amount of electricity generation in these scenarios.

The fatalities from transporting coal in each of the scenarios range from 1600 to 2400 people per year. Each fatality is valued at $5.2 million, with this social cost included in the system cost calculation. The main factor determining this rate is the ton-miles of coal shipped. These fatalities come from all phases of the life cycle except the deaths due to air emissions from the power plants (Kammen and Pacca, 2004). Instead, the air pollution fatalities are shown in the social cost of each pollutant emission.

Accounting for the social costs in Fig. 1 does not influence the decision about which technology is cheapest. This is primarily due to the high fraction of SO_2, NO_x, and PM emissions removed using currently available control technology. The increased efficiency of the ultra-super-critical PC plant results in a cheaper system than the IGCC system. However, when CCS is added, there is a greater energy penalty associated with operating an amine scrubber on a PC plant than the water gas shift reactor and Selexol system on the IGCC plant. This results in system costs that are essentially identical ($10.5/kWh and $10.6/kWh, respectively). This result changes depending on the coal type that is being used. This issue has been addressed in more detail elsewhere (Bergerson and Lave, 2007).

The system costs, and their proportion, vary among scenarios, as shown in Fig. 2. Again, CO_2 emissions are considered in Section 4.2. For the CCS scenarios, the largest increase in cost comes from the generation phase.

4. Air emissions

Fig. 3 shows the air emissions from current coal plants and from all current electricity generation. The comparison of the two shows that coal is responsible for the vast majority of air emissions, even though it represents only half of the generation. NGCC plants have low capital cost, and have low pollution and CO_2 emissions, as Fig. 3 shows. It is easy to see why the plants were so attractive when gas was priced at $3/MMBtu. Fig. 3 shows that the coal plants have much higher CO_2 emissions, unless they are equipped with CCS.

The minemouth generation scenarios are based on PC technology and reflect the increased emissions from

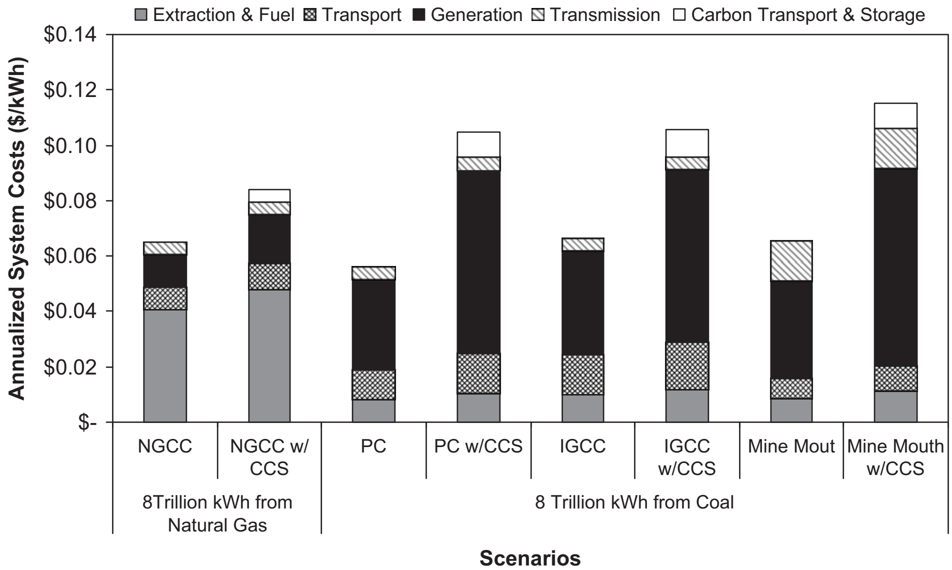

Fig. 2. Annualized system costs by life cycle phase for coal and natural gas scenarios.

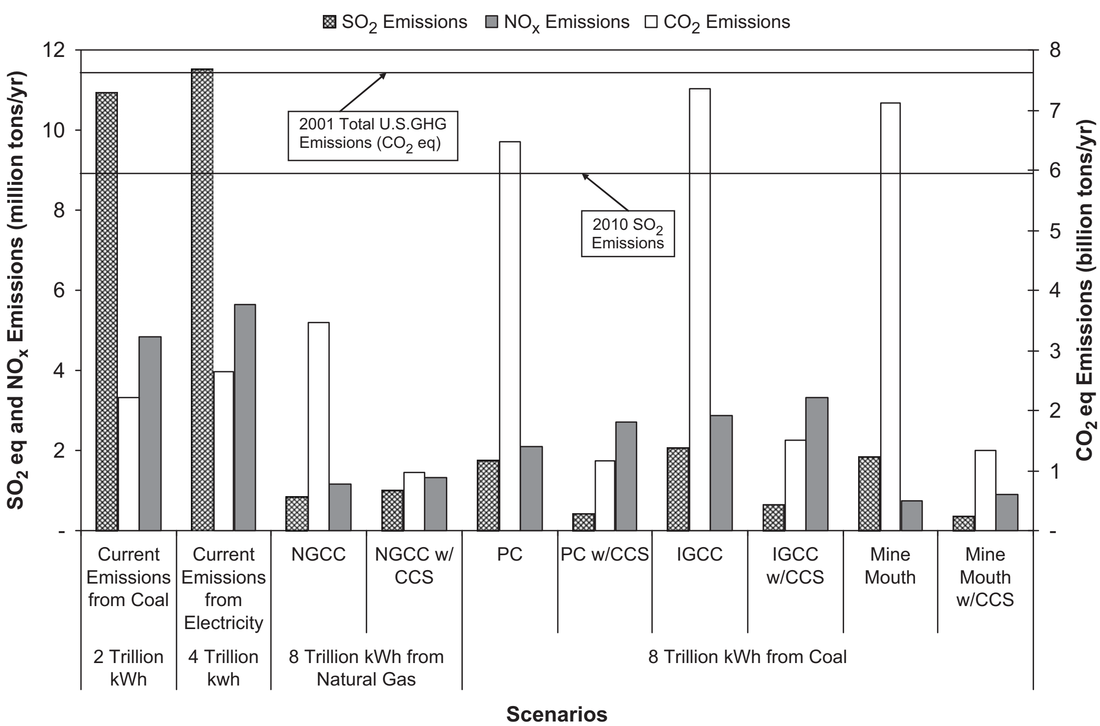

Fig. 3. Annual life cycle emissions (SO_2, CO_2, and NO_x) for coal and natural gas scenarios.

roughly 9% more coal required to compensate for the line losses associated with the transmission line transport of the energy. The only exception is the NO_x emission, which decreases from the PC scenario, since the rail NO_x emissions are avoided.

Different processes are used to remove the sulfur from the PC and IGCC plants. The latter removes the sulfur in the form of H_2S while the former removes SO_2 from the flue gas, offering greater control. NO_x removal is also slightly better in the PC plant, reflecting the differences in efficiency. The NO_x emissions increase slightly when CO_2 capture is included. Since CCS decreases the efficiency of the plant, the first 20–30% of CO_2 removal is required to make up for the efficiency loss.

4.1. SO_2 emissions

Sulfur emitted from power plants is currently regulated by a cap and trade system. The 2010 SO_2 emissions cap shown in Fig. 3 (8.95 million tons) (EPA, 2004) is not met

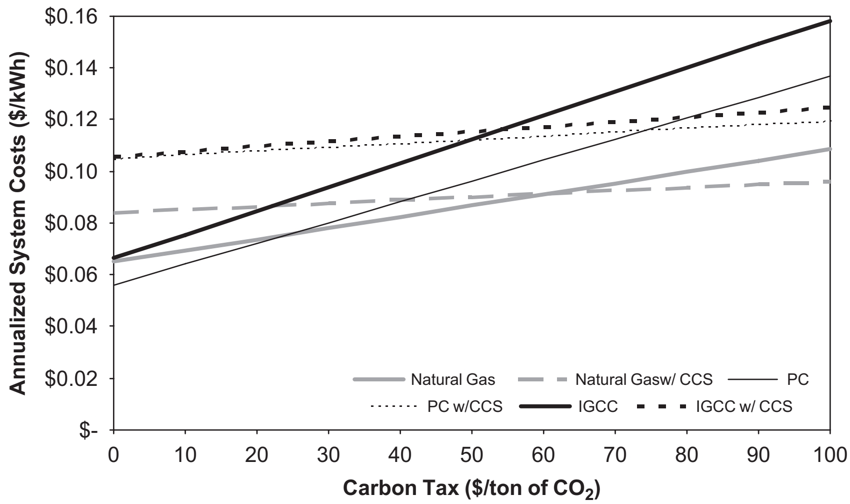

Fig. 4. Change in system cost with changing carbon dioxide tax.

by the current generation but would easily be met by burning four times as much coal with advanced technologies (which remove 98% of sulfur).

4.2. How does the value of carbon impact the results?

Fig. 3 shows that producing 8 trillion kWh annually results in much greater life cycle GHG emissions than at present, even if natural gas is the fuel. Requiring CCS reduces GHG emissions by between 85% (for the NGCC scenario) and 60% (for the IGCC scenario) below current levels. Without CCS, the natural gas scenario has about half the GHG emissions of the coal scenarios. However, when CCS is included, the emissions are comparable, due to the relatively large energy penalty of the amine scrubber on the NGCC system and the upstream GHG emissions.

Since the social cost of CO_2 emissions is still uncertain, it was not included in the system costs. Fig. 4 shows how non-CCS and CCS scenarios compete at varying carbon taxes.

The dashed lines in Fig. 4 represent scenarios with CCS; the scenarios without CCS are represented by solid lines. As the carbon tax increases, costs rise rapidly in the scenarios without CCS. The cost for the CCS scenarios increase more slowly, since 90% of the carbon is being captured from the generation phase. For the IGCC, PC, and NGCC plants, the carbon dioxide tax would have to be at least \$53, \$74, and \$61, respectively, to make it cheaper to add CCS to the plants.

Fig. 5 breaks down the emissions from the CCS scenarios shown in Fig. 3 into the life cycle stages that are responsible for the emissions.

A large fraction of the CO_2 equivalent emissions in the "extraction and fuel" category are from the methane released during the mining process. However, the amount of methane released depends on the mining method. For example, the CO_2 equivalent emission factor for underground mining (0.14 tons of CO_2 eq/tons of coal produced) is over eight times higher than surface mining (0.017 tons of CO_2 eq/tons of coal produced). In general, the amount of methane trapped in coal is higher with increasing coal rank. Since methane is also a greenhouse gas and natural gas prices are uncertain, there is potential for these emissions to decrease over time due to increased extraction of this methane during mining.[1]

Fig. 6 contrasts current GHG emissions from the US economy with emissions from the CCS scenarios from this analysis. The columns in the figure labeled electricity, transportation, industry, agriculture, commercial, and residential sum to the total GHG emissions emitted in the US today as estimated by the EPA's inventory of US Greenhouse Gas Emissions and Sinks (EPA, 2003). The other four columns are the CCS emissions scenarios considered in this analysis. The results in this figure show that even with 90% removal of CO_2 from the generation phase, the life cycle CO_2 emissions are significant and comparable to the major economic sectors in the US today. This means that 90% CCS removal efficiency, although being a large improvement over current electricity generation emissions, results in life cycle emissions that are large enough that additional effort is required to achieve significant economy-wide reductions in the US for this large increase in electricity generation using either coal or natural gas. There are technologies currently available to address some of these emissions. For example, it is possible to capture methane from underground coal mines. It is also possible that future versions of capture technology can

[1]The distance that coal is transported differs by coal type, e.g., subbituminous coal from Wyoming is shipped an average of 1100 miles, whereas bituminous coal like Illinois Coal no. 6 is shipped an average of 400 miles, and lignite less than 50 miles. The distance shipped influences emissions.

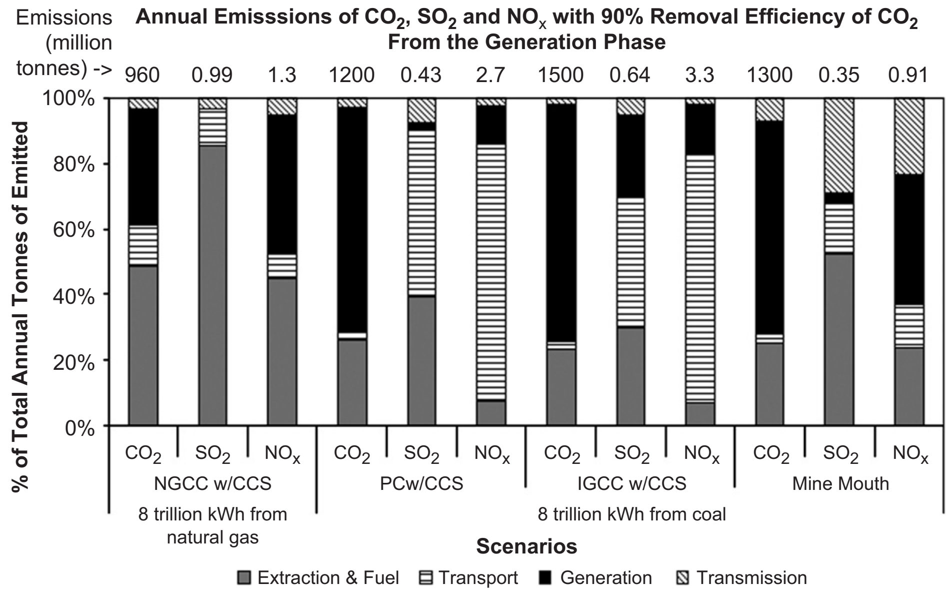

Fig. 5. Emissions of CO_2, SO_2, and NO_x by life cycle stage (assuming 90% removal of CO_2 from generation).

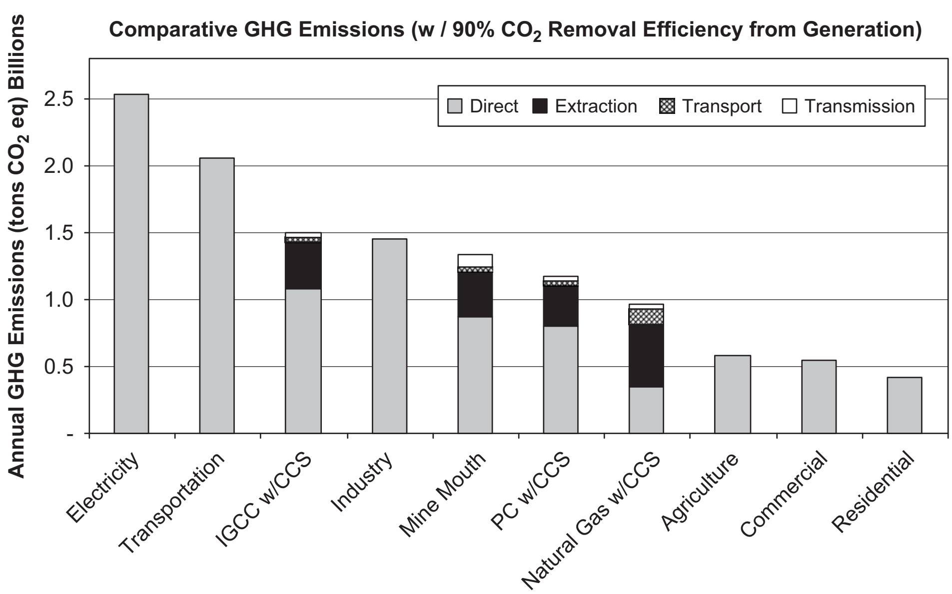

Fig. 6. Comparison of GHG emissions between current economic sectors and future scenarios for electricity production (90% CO_2 removal efficiency in the generation phase of future scenarios).

increase removal efficiencies from the generation phase above 90%.

5. Effect of increased use of different coal types

Extraction costs, sulfur content, transport costs, environmental regulations, and generation technology can change the mix of coal types used over time. This section explores the impacts associated with potential shifts in coal type use from the current proportional contribution from different coal types summarized in Table 2. For example, Western coal has been moving into markets previously supplied by Eastern coal. The EIA projects that Western coal will continue to penetrate Eastern markets, although at a diminishing rate to 2020 (Flynn, 2000). They project that the proportion of Western coal produced (which is 81% sub-bituminous coal (EIA, 2003a) will increase from 51% to 59% in 2020 (EIA, 2002). Since the AEO considers projects based on a continuation of current trends, the EIA also projects that productivity gains (attributed to maintaining coal prices in the past) will continue over time but will slow down gradually. They assume that the average productivity gains will be 2.3% per year to 2020. Since productivity (tons produced/employee-hour) is higher for surface mining than underground mining and productivity is increasing at a faster rate for surface mining (Resources for the Future, 1997), the EIA projects that coal prices will decrease slightly to 2020. Whether these trends will continue after 2020 is uncertain and doubtful if coal use quadruples. Western coal is attractive because of its low mining costs and low sulfur. Undermining its appeal is the lower energy content and the long distances to many markets. Eastern coal could become more attractive if underground mining is automated, lowering the cost, if the shorter distances to market become more important, or if the coal is more easily gasified. The low sulfur content of PRB coal becomes unimportant as all plants must meet NSPS. The current difficulties in transporting Western coal raise the possibility that the rail system could restrict the amount of Western coal that will reach Eastern markets. Mercury control may be important in the competitiveness of the coals.

As the more easily mined seams are depleted, Eastern coal costs will rise. A large expansion in coal use will increase transport costs, although less so for Eastern coal, since it is located closer to the market.

The capital cost of generating plants using Western coal is higher than plants using Eastern coal due to the decreased energy content of the fuel and efficiency impacts associated with water and ash contents. The greater distance between mine and market for Western coal is largely offset by the lower transport price per ton-mile. If major investment in rail infrastructure is not made, Western coal use will be restricted in Eastern markets (NAS, 2002; EERE, 2004; RAND, 2000).

Surprisingly, scenarios that investigate shifts as large as 80% Eastern versus 80% Western coal have system costs that are comparable in magnitude to those shown in Fig. 1. However, the contributions from each life cycle phase differ for each scenario, and many of the differences offset each other.

Since the CCS technology is still being developed, the 90% removal rate and cost are likely to improve. In most of these scenarios, the emissions from mining dominate the life cycle emissions for most scenarios. However, in a scenario where 80% of the electricity comes from Western coal, the increased transportation requirement is an important contributor to the overall emissions. The sensitivity analysis conducted to evaluate the relative impacts of a different proportion of coal types shows that very different impacts occur depending on the assumptions made.

6. Can coal compete with natural gas?

Four billion tons of coal or 49 TCF of natural gas would be required to produce 8 trillion kWh per year. The US has such large coal reserves that it seems likely we could mine 4 billion tons per year with little increase in the per ton extraction cost for most scenarios. The availability of natural gas is entirely different.

Total US dry gas proved that reserves are currently 189 TCF. Production rates are roughly 10% of proved reserves and this is increasing as seen in Fig. 7. The EIA projects natural gas consumption to increase to roughly 30 TCF/year by 2025; a linear extrapolation results in consumption of 40 TCF/year by 2050. Electric power generation consumed close to 5 TCF of natural gas in 2003, 23% of the total natural gas consumed in the US.

Even the 40 TCF projection would likely result in higher prices since significant imports of LNG, the ability to make use of methane hydrates, or the conversion of other fossil fuels to gas would be required. Without significant discoveries or these other resources, the US natural gas reserves would be inadequate to continue this level of production to 2050.

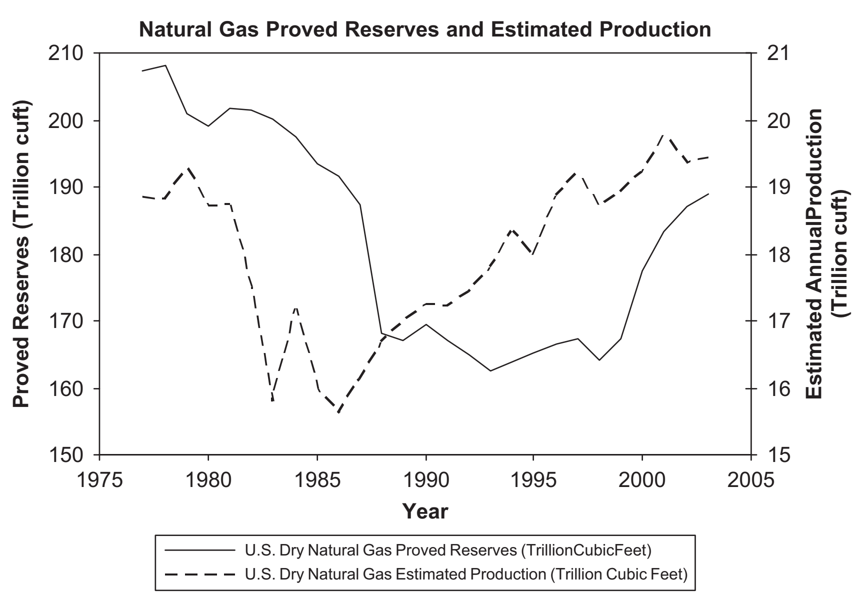

Fig. 7. Annual estimates of dry natural gas reserves and production (*Sources*: EIA, 2003b, c).

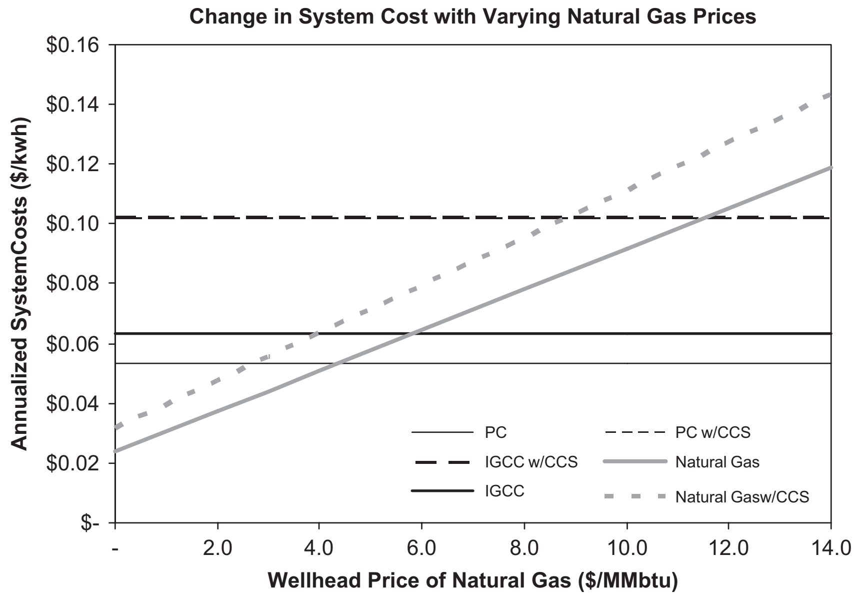

Fig. 8. Effect of natural gas price on the annualized system costs.

Natural gas prices are likely to change from the \$7.0/MMBtu assumed in the base analysis. Fig. 8 shows a range of prices for natural gas and the impact price has on the competitiveness of the natural gas scenarios against the coal scenarios.

When CCS is not used, the price of natural gas would have to be less than \$4–5/MMBtu to compete with PC and IGCC, respectively. When CCS is required, the price of natural gas would have to be higher than \$9.0/MMBtu before coal is more competitive.

7. Conclusions

The abundance of coal and its low cost make it likely that coal will continue to be a major fuel for electricity generation in 2050. A high coal future that quadruples US coal mining, transport, and electricity generation would pose considerable environmental challenges. Advanced technologies for generation and control of pollution and greenhouse gases could more than offset the emissions increases. The advanced technologies needed to achieve 98% reduction of SO_2, 95% reduction in NO_x, and 90% reduction in CO_2 would increase the life cycle generation cost of electricity from roughly 5.4–11.6 cents/kWh; they would also lower the external costs considered in this analysis of electricity production. Quadrupling coal usage with current levels of control would result in high air pollution levels with high social costs.

The inclusion of air pollution, greenhouse gas, and other discharges of coal burning electricity plants into the system costs is important and requires a life cycle perspective. We include advanced pulverized coal and gasification plants with and without CCS technology. Scenarios with 2.5 times current electricity production in 2050, 80% of which is produced from coal, require roughly four times the amount of coal mined today. Even with 100% CO_2 removal from the generation phase, CO_2 emissions from the rest of life cycle are comparable to the other major sources of CO_2 in the economy today, although less than current CO_2 emissions from electricity generation. If natural gas were abundant, this cleanest of the fossil fuels would produce less CO_2. However, the higher electricity growth scenario would require such a large amount of natural gas that there is unlikely to be sufficient supply at an attractive price.

Our analysis does not consider the environmental problems, such as land and water impacts, associated with mining 4 billion tons of coal each year. The scenarios that focus on Eastern coal are likely to pose formidable environmental challenges. Transporting this much coal and finding sufficient water for generation pose further problems. We conclude that advanced technologies can make a four-fold increase in coal use more benign than current generation, but considerable environmental problems will remain in mining and transport.

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