

COAL OR GAS: THE COST OF CLEANER POWER IN THE MIDWEST

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Coal or Gas: The Cost of Cleaner Power in the Midwest
Henry Lee and Shashi Kant Verma*

EXECUTIVE SUMMARY

Many of the loudest debates in environmental policy have focused on two issues: climate change and transported air pollution. In attempting to resolve these issues, considerable attention has focused on coal-fired electricity generating plants in the Midwest. For advocates of a more proactive policy aimed at carbon reductions, these plants offer an attractive target with large potential reductions. For opponents, these proposed emission reductions raise the spectra of higher electricity prices and the potential erosion of the region's economic competitiveness.

The debate, though, has not focused on what it would cost to bring about change in the Midwest. At what cost would Midwest coal-fired electricity generating plants convert from using coal to relying on natural gas? This paper identifies the factors influencing the answer to this question and provides estimates of both their magnitude and the uncertainties surrounding them.

Since the Clean Air Act of 1970, Midwest and Northeast states have argued over how to allocate the economic costs of meeting the nation's air pollution reduction goals. This regional battle has been fought over acid rain, nitrogen oxides (NO_x) and submicron particles, and is likely to be fought again over carbon dioxide (CO₂).

The paper begins with the premise that the owners of these generators are self-interested and if the cost of burning coal is expected to be greater than the cost of burning other fuels, they will either convert their facilities away from coal or retire them in favor of either a new gas-fired facility or non-fossil-fueled options.

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At the moment, Midwest coal plants can be operated at slightly more than 50 percent of the capital and operating cost of a new gas-fired facility. What factors would shift this cost differential? The paper identifies three: a) the cost of meeting the requirements of the Clean Air Act Amendments of 1990 (CAAA) and the new EPA reduction initiatives, such as additional NO_x reductions and the proposed particle and ozone standards, b) the relative prices of natural gas and coal delivered to the plant, and c) the cost of carbon emissions, which is presently zero, but could rise if the United States decides to meet future international greenhouse gas reduction targets.

Conventional Air Pollution

Often, studies of the cost of reducing carbon emissions forget that coal-fired power plants must meet major new emission reduction targets, and these will significantly increase their cost of operation. In fact, a small percentage of the older coal plants are likely to be closed as companies implement emissions cutbacks to meet the new CAAA requirements.

The paper looks at sulfur dioxide (SO₂), NO_x, suspended particles, and mercury and concludes that requirements to reduce those four pollutants could add between 0.7 cents and 1.36 cents per kWh to the cost of coal-fired generation in the Midwest, with our best guess being a 1 cent per kWh increase. That is, marginal wholesale costs will rise from about 1.6 cents to around 2.6 cents per kWh. This cost is still more competitive than that of a new gas-fired plant, but it substantially narrows the differential between coal and gas. There are many uncertainties surrounding these numbers, but three stand out:

- 1) Will the US government endorse national emissions trading for NO_x? If it does, it could reduce by up to 50 percent the cost of meeting proposed NO_x emission standards, depending on the severity of the new reduction requirements. In the short term, a lower standard will result in fewer benefits from trading, while a less stringent standard will result in greater benefit, but this will change as new NO_x abatement technologies come on line.

- 2) How will the EPA decide to meet its proposed new ambient standards for suspended and submicron particles, assuming the standards survive the numerous court challenges? Will the schedule for compliance be as generous as it now seems? Some coal-burning generators could wait until 2014 to make abatement investments, effectively separating particle investment decisions from those for SO₂ and NO_x.
- 3) Will scrubber technologies continue to improve, and will the price of scrubbers serve to cap prices in the sulfur allowance market? If it does, sulfur allowances are unlikely to exceed \$250 per ton for any length of time.

Natural Gas

Many Midwest utilities recognize that the cost of conventional pollution abatement will drive up the price for wholesale electricity, but argue that continued price volatility in the natural gas market, compared with low and declining wholesale coal prices, creates strong economic incentives to remain on coal.

Forecasting future natural gas prices is an exercise fraught with peril. Studies have shown, however, that these prices are primarily a function of projected resource levels. If one believes the resource is more limited, one will forecast higher prices than if one believes it is more plentiful. Based on a review of existing studies and conversations with experts in the industry, this study is more biased towards the higher resource predictions. As a result, we forecast long-term prices in the \$2.50 to \$3.00 (\$1998) per mcf range.

The authors further conclude that the transmission and distribution investments needed to meet even the high growth scenarios do not dramatically exceed historical levels and could be made without significant increases in wholesale prices. The authors also find that a vast majority of the larger electric generation plants in the Midwest are within 10 miles of an existing major gas pipeline.

Carbon

If, by the end of this decade, the United States decides to significantly reduce its carbon emissions and switch Midwest capacity from coal to natural gas, what will it cost? The study assumes that if the cost of continuing to operate an existing coal plant is higher than the expected cost of building and operating a new gas-fired facility, electricity generators will opt to change significant percentages of their capacity mix from coal to gas. What cost increases will be needed to realize these conditions? Since investments in conventional pollutants will not erase all of the competitive cost advantages of coal-generated power, especially in a period of volatile and rising gas prices, what additional cost increases might tip the balance?

If reducing carbon emissions is the goal of changing the fuel mix, then the most logical option for governments would be to take actions that would cause the market to assign a price value for carbon emissions. A tradable carbon permit program, a mandatory emission reduction, or a carbon tax would achieve this result.

The study attempts to determine the percentage of existing coal capacity that will become less competitive than new gas-fired capacity at different carbon costs. It looks at several scenarios and projects that more than 60 percent of the region's coal capacity will be uneconomic compared to gas at a carbon penalty between \$22 per ton and \$142 per ton. This range is huge and represents an upper and lower limit. The study's best estimate is that a \$60-\$85 per ton carbon penalty will come close to realizing the 60 percent target, increasing Midwest retail electricity prices by about 1.5 - 2.1 cents to around 10-10.6 cents per kWh.

The study concludes by making several recommendations, including the establishment of a "multi-pollution approach" to emission reductions. Previous efforts to persuade either regulators or emitters to address all the criteria pollutants plus carbon simultaneously have met with political and administrative resistance, but the long-term benefits of such an approach could have measurable economic and environmental benefits.

I. INTRODUCTION

Since the inception of the clean air debate in the late 1960s, coal-fired electricity generation has been a major target of environmentalists and regulators alike. In the 1970s, their focus was conventional pollution; in the 80s it was acid rain; and in the 90s, it has fluctuated between transported pollutants and submicron particles. At the beginning of the new decade, attention has moved to carbon emissions, where coal plants are again the focus of debate.

Many of these coal plants are located in the seven Midwest states that comprise the East Central Area Reliability Coordination Agreement (ECAR) and the Mid-America Inter-connected Network (MAIN) electricity regions of the North American Electricity Reliability Council (NERC) - Ohio, Indiana, Illinois, Michigan, Wisconsin and small portions of Pennsylvania and West Virginia. This concentration has allowed the debate to evolve into a regional *political* struggle between the northeast states who pay higher electricity prices and find themselves downwind from the Midwest power stations and the Midwest states which enjoy less expensive electricity.

In recent years, the regional debate, which had focused on acid rain and ground-level ozone expanded to include climate change and particularly carbon emission. The relative concentration of coal plants in the Midwest and the perception that they are more polluting than coal plants in other regions, makes the Midwest a particularly attractive target for environmental advocates. If the 88,000 megawatts (MW) of coal generation in the ECAR and MAIN regions could be shifted from coal or closed down, approximately 125 million tons of carbon emissions would be reduced--or approximately 25 percent of the 2010 stabilization target.¹ To further stoke this idea, advocates point to studies that show that Midwest coal plants will almost certainly be used more fully as demand

¹ The Energy Information Administration estimates that in 1997 total emissions of carbon dioxide from the United States was 1,500 million tons carbon equivalent. Out of this 471 million tons is directly attributable to coal fired electricity generating plants, with a total nameplate capacity of 325 GW. [US Department of Energy's Information Administration Form. EIA-764, "Steam-Electric Plant Operation and Design Report." Washington, D.C.: US Department of Energy.]. About 500 million tons of reductions in carbon emissions from the business as usual case is required for compliance with the Kyoto Protocol [EIA, 1999(b). Annual Energy Outlook - 1999: Report # DOE/EIA-0383(99), Washington, D.C.: US Department of Energy.].

increases.¹ The cost of investing in new generating plants is significantly higher than increasing the use of old ones and there is sufficient underused capacity that could be refurbished to increase plant load factors.² Hence, the carbon reduction potential from the Midwest may be even higher. In any case, it forms a significant and easy political target for reductions.

Any serious discussion of reducing the amount of coal-fired generation in this region must assess the policy options in the context of political and economic realities. Utilities choose to operate coal-fired power plants because they are generally less expensive than most alternatives. In 1996, the incremental cost of generating power from coal-fired plants in MAIN and ECAR averaged around 1.6 cents per kWh, while the cost of building a new gas facility was approximately 3.1 cents. Given such a wide price differential, it is not surprising that consumers and producers alike are not anxious to switch to gas.

What factors might alter this perception? While it is possible that people might become more conscious of the dangers of climate change, it is unlikely to result in actions that would persuade them to voluntarily double wholesale power prices. Thus, the only scenario that might induce producers and consumers to change the mix of electricity generation would be one in which coal-based electricity became considerably more expensive relative to other possible sources--particularly natural gas.

There are two factors that would trigger such a scenario: changes in fuel prices and stricter environmental requirements. Any change in coal and gas prices that favors generation from the latter would further increase the incentive to switch to gas generation. Coal prices, though, have been steadily declining in real terms and are now hovering around \$1.00 per mmBtu, while wellhead natural gas prices have been fluctuating above the \$2.00 per mmBtu level. Most experts do not expect this differential to change appreciably, and, those who do, predict that the change will favor coal, not gas.

² Ellerman shows the increasing use of coal plants in the Midwest. Roughly two-thirds of increased generation during the 1990's came from increased use of coal plants. The rest came from new gas plants. Ellerman, A. Dennis. 1996. The Competition Between Coal and Natural Gas - The Importance of Sunk Costs. *Resources Policy* 22(1-2) 33-42 Mar-June.

The second factor is stricter environmental standards. In the near term, electricity generators confront a new round of sulfur reductions and significant reduction in NO_x emissions. In the longer term there is a strong probability that they will also have to ratchet down particulate emissions. These requirements could increase the average cost of wholesale electricity in MAIN and ECAR from about 1.6 cents per kWh in 1996 to about 2.6 cents in 2012. As we will discuss later, there is considerable uncertainty around these numbers. But, given the absence of a strong economic analysis of the cost of reducing particles and the normal uncertainties surrounding possible advances in control technologies, an average increase of 10 mills seems reasonable.³

A cost of 2.6 cents inclusive of fuel and the cost of compliance with air pollution regulations are still below the estimated cost of building and operating a new gas plant and thus, if our estimates tire in the ballpark, few coal plants will be rushing to close down. In fact, with the help of an effective maintenance program, a coal-fired plant can extend its life way beyond the advertised forty years. Thus, while the cost of conventional pollution abatement may result in the closure of the oldest and least efficient units, most of the coal-fired plants should be able to function very profitably.

This leads us to believe that any expectation of a collateral benefit of carbon abatement as a result of proposed tighter air pollution regulation is unfounded. Indirect measures for controlling carbon emissions are unlikely to work, and if the objective is to reduce carbon emissions, direct measures will need to be invoked. On the other hand, as our study shows, there may be a significant dividend in terms of improved air quality if some regime for carbon abatement is established.

If and when the United States decides to embark on a serious effort to reduce its carbon emissions, it will most likely rely on one of two options--a tradable permit

³ While the effects of tighter emissions standards will be felt all around the electricity industry, especially by coal plants, some plants will be more affected than others. For example, pit head plants that use especially dirty coal are likely to have the greatest increases in compliance costs. However, many of these pit head plants are also the cheapest to operate. While the average cost of compliance by itself forms an interesting statistic in that it gives some idea of the increased cost of electricity the environmental effects can be analyzed only by studying the marginal plants.

program or a carbon tax.ⁱⁱ Either one will result in establishing a market value for carbon reductions that will show up in the price of fossil fuels. These price hikes will affect carbon-intensive fuels, such as coal, more significantly than less carbon intensive fuels, such as natural gas. What is the size of the carbon penalty that would be required to make it profitable for coal generators to switch to natural gas? This paper attempts to answer this question.

In assessing the relative economics of coal and gas generators under different assumptions of pollution abatement and fuel costs, it is important to remind the reader that the marketplace, into which these facilities will be selling, is changing from one characterized by cost-of-service regulation to one characterized by competition. In the latter, the wholesale price of electricity will be set not by regulators and not according to the costs of production, but by the price of the marginal unit of power offered for sale at any given time period. In a highly competitive marketplace, suppliers will be willing to produce at prices as low as their short-term marginal cost, which will be equal to their cost of fuel and routine operations and maintenance. Thus, for an existing facility, its short-term cost will be the cost of fuel and operations and maintenance, but for a new facility, the comparative costs will include both variable and fixed costs. The reason is simple. Why would a developer build a new facility if he or she knew that the price would not cover the fixed costs? But if one already had a facility operating, it would make equal sense to continue to operate it as long as it was covering its operating costs and periodically making a contribution to its fixed costs. The investor in the new facility has the option not to build, but the owner of the existing facility does not have that option. Hence, it is legitimate to compare the costs of operating existing coal facilities to the all-inclusive costs of a new gas facility.

Given this construct, why do we add capital costs for pollution control to the operating costs of coal plants? These costs are discretionary in that a plant owner theoretically will not assume these costs if he does not believe he can recoup them in the market. If he wants to operate the plant, he will need to make the investment in pollution reduction in the same way he now has to make the investment in fuel. If he does not, the

government will not allow him to operate it. Hence, it is legitimate to add the incremental cost of pollution abatement to the operating cost of an existing facility.

The paper is organized into four parts. The first describes the electricity generation sector in MAIN and ECAR. The second discusses the estimated costs of meeting conventional air pollution requirements, and the third provides a projection of future natural gas markets. Given these two estimates - - for conventional pollution abatement and for future gas price trends - - we can calculate the level of carbon values that will be needed to stimulate significant switching away from coal and towards natural gas. To complement this calculation, we look at several alternative assumptions and calculate how they would change our conclusions.

II. MIDWEST ELECTRIC GENERATING SECTOR

Description of Plants

Table 1 shows the capacity existing in the ECAR and MAIN regions at the end of 1997. Nationally, 43% of the existing capacity relies on coal. However, the ECAR and MAIN regions rely on coal for 71% of their capacity. The coal capacity in these regions represents 37% of the total coal capacity in the USA. We concentrate our analysis on all coal plants with a nameplate capacity of 5 MW or more in Illinois, Indiana, Kentucky, Michigan, Ohio, Wisconsin and West Virginia. Our data represents a total of 412 coal-fired boilers and 103,796 MW of capacity or approximately 89% of the coal-fired capacity in the region

Table 1: Existing Capacity by Energy Source, end-1997

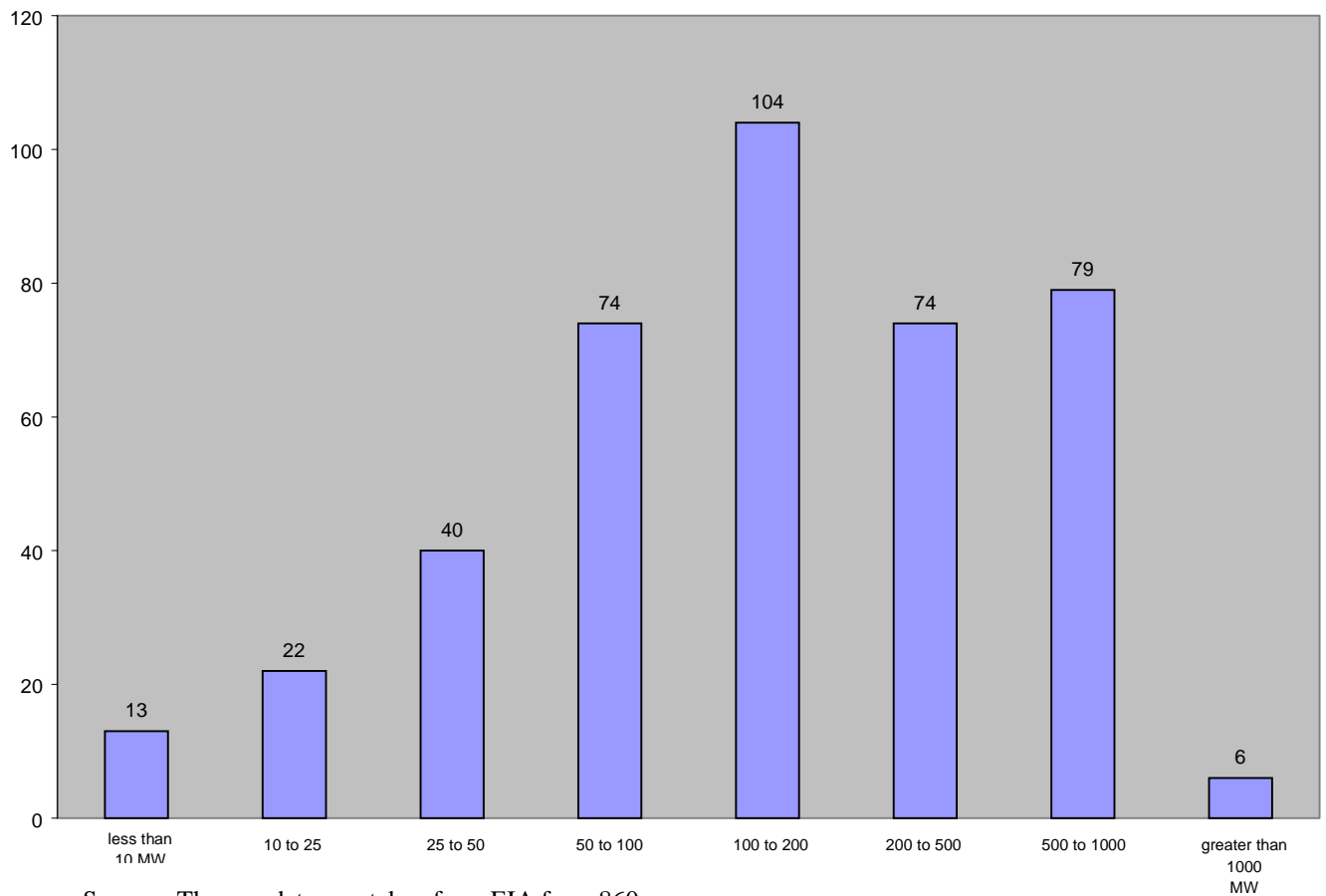
	MAIN	ECAR	Total	USA	% in ECAR and MAIN
Coal	28,483	88,110	116,593	320,593	36.4
Oil	3,012	5,261	8,273	69,812	11.9
Gas	6,009	4,857	10,866	135,426	8.0
Hydroelectric ⁴	1,053	3,445	4,498	91,156	4.9
Nuclear	14,357	8,276	22,633	104,757	21.6
Other	2	91	93	6,500	1.4
Total	52,916	110,039	162,955	728,259	22.4

Source: EIA: Inventory of Electric Utility Power Plants in the United States, 1999; Table 14

Fifty-seven percent of this capacity comes from facilities larger than 500 MW and another 21% from plants between 200 and 500 MW. While there are many plants smaller than 200 MW, the capacity they contribute is small. Figure 1 provides a size distribution of plants.

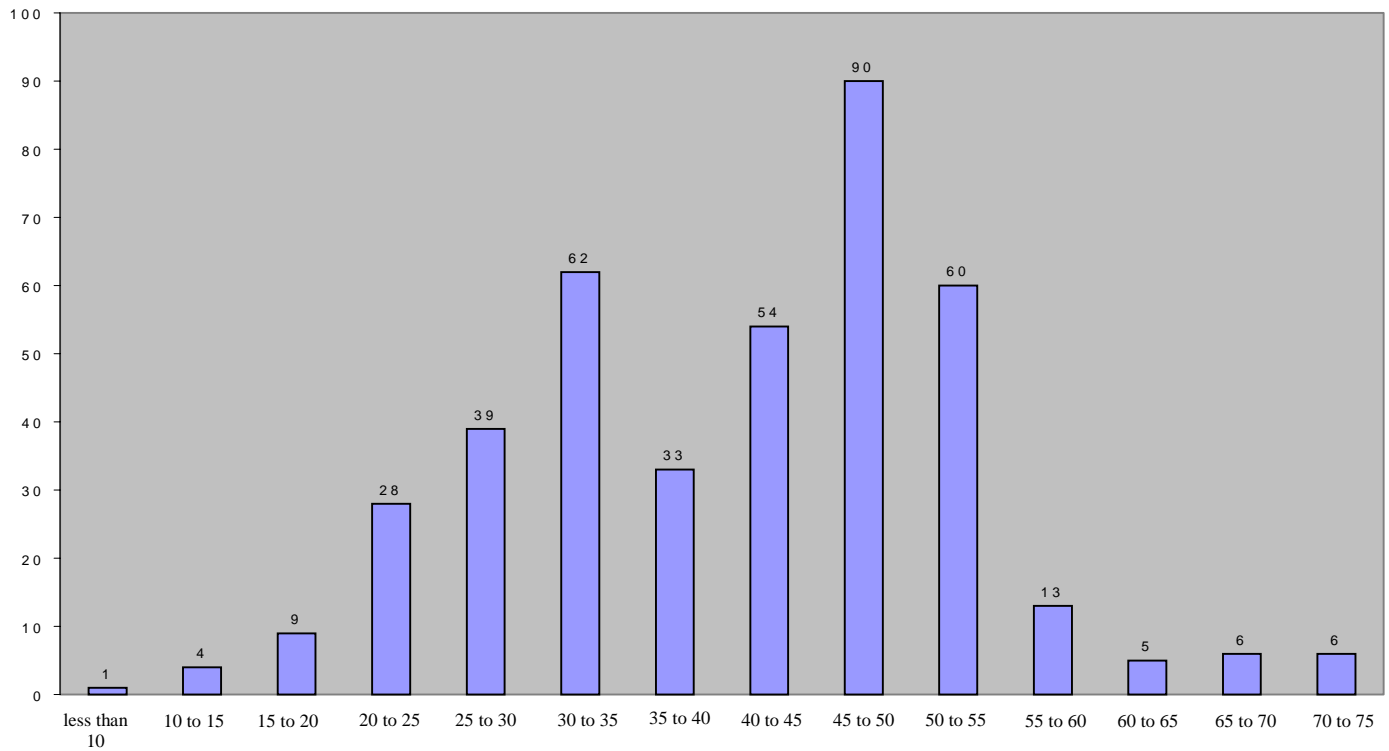
⁴ Hydroelectric includes pumped storage capacity

Figure 1: Size Distribution of Plants in ECAR and MAIN (1996)



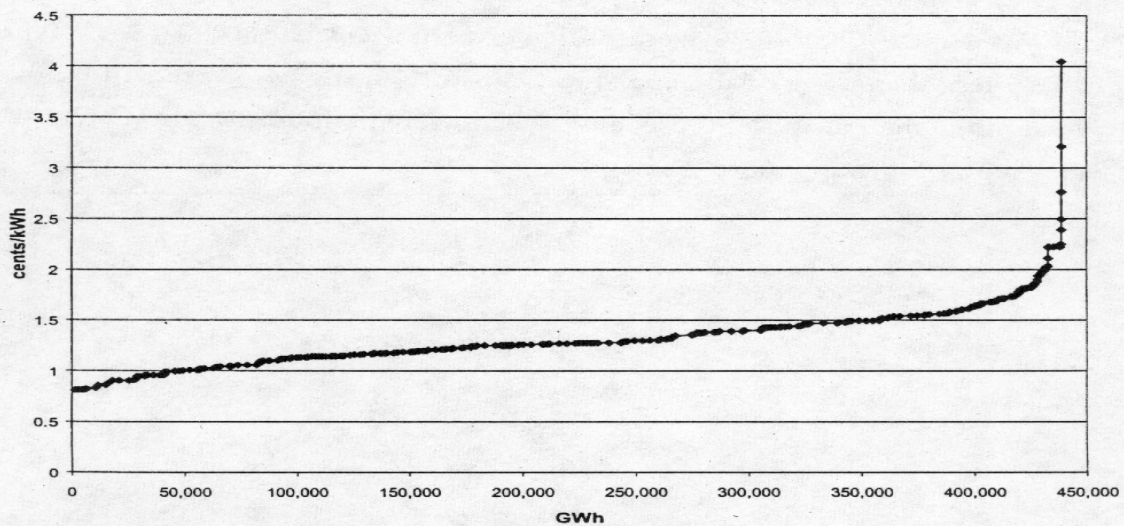
While some coal-fired plants are over 75 years old, the vast majority is less than 50 years old. Over 70% were built between 1957 and 1977 (See Figure 2). In fact in 2010, less than 18% of the coal-fired capacity in the Midwest will be over 50 years old. Assuming that most of these have been well maintained, they should be able to run efficiently for many more years.

Figure 2: Age Distribution of Plants in ECAR and MAIN (1996)



Source: The raw data was taken from EIA Form 860

Figure 3: Fuel Cost Curve for Coal Plants in ECAR and MAIN



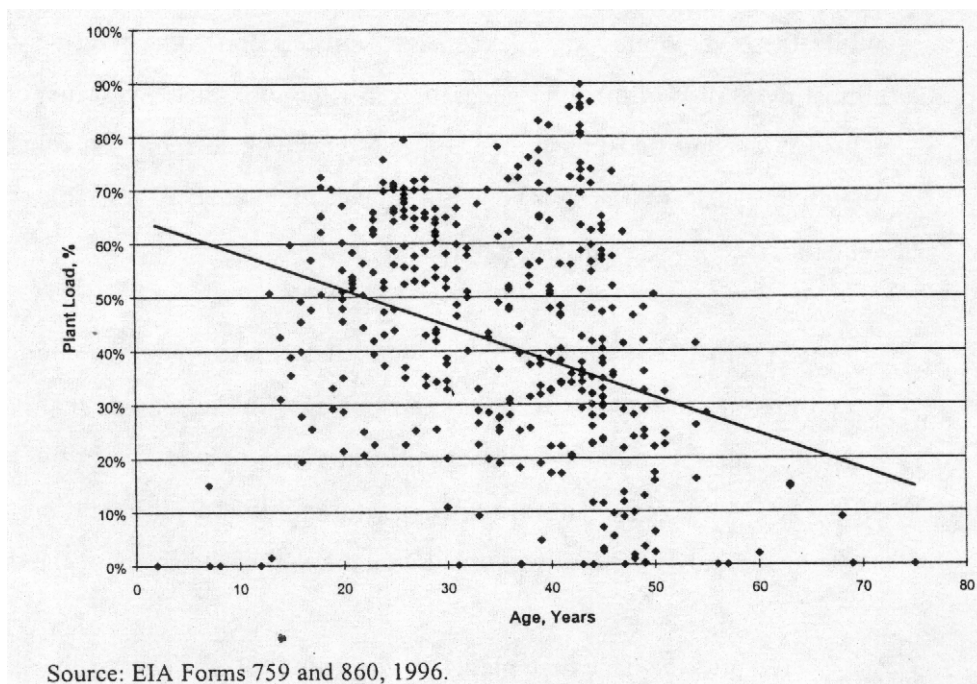
Source: EIA Forms 423, 759 and 860, 1996.

Figure 3 presents a fuel cost curve for coal-fired electricity for the year 1996. While there are some very inexpensive facilities and some relatively expensive plants, almost two-thirds of the total generation in 1996 took place with fuel costs between 1-1.5 cents/kWh. Note that this is not a supply curve since there are other variable costs of operation, such as variable operation and maintenance, variable costs of pollution abatement, etc., which are not included in the chart.

The fuel cost curve is much flatter than those for other regions that use a more varied mixture of fuels to generate their power. Unlike regions that have significant gas or hydro capacity, the only other significant generation source in the Midwest is nuclear energy. Since nuclear plants are relatively inflexible in their operation, they would appear at the lower end of the cost curve, but would not alter the shape of the curve.

Despite the fact that plants in the Midwest are cheap, the lack of plants used specifically to meet peaking loads means that significant spare capacity needs to be maintained in order to meet load. In 1996, the average utilization rate of these facilities was 48.2% with facilities built in the last 28 years being used slightly more than the facilities built earlier (See Figure 4).

Figure 4: Age and Utilization of Plants in ECAR and MAIN



If further increases in demand were consistent throughout the day, most parts of the Midwest would not have to build new capacity for quite some time. They could simply increase the use of their existing coal-fleet. However, increases in demands during peak load periods should increase the demand for peaking plants. Deregulation that leads to plants getting compensated according to hourly pool prices might further enhance the move towards the construction of peaking plants. However, any increase in base load can safely be met by increasing the intensity of use of existing coal plants. Unless new plants can be built at costs lower than the cost of coal generation, new plants will be unable to displace existing coal generation for base load.

In summary, the Midwest fleet of coal-fired generating plants produces power at very competitive prices and are likely to be able to continue to do so for many years to come. Further, the homogeneity of production costs almost assures that as the demand for power increases the industry can meet new demand by increasing the utilization of its present fleet. New facilities simply cannot compete with the existing fleet and there is no incentive to retire these units.

III. MEETING AIR POLLUTION REQUIREMENTS

The Clean Air Act Amendments of 1990 (CAAA) ushered in a new era of air pollution regulation. Where earlier acts had focused on localized pollution effects, the CAAA targeted transported pollution and specifically the precursors to acid rain and smog. Older plants that heretofore had been able to avoid the stringent standards faced by newer plants were mandated to reduce their emissions of sulfur dioxide (SO₂) and nitrogen oxides (NO_x). In addition, EPA is grappling with the possibility of new and significant reductions for small, airborne particles and possibly mercury.

To reduce sulfur dioxide (SO₂) emissions, Congress decided to rely on a cap and trade program, while for NO_x, it chose to maintain the traditional system of emission standards. Hence, the impacts of each of these regulations on the Midwest coal fleet will be different.

Sulfur Dioxide

Title IV of the CAAA aimed "to reduce the adverse effects of acid deposition through restrictions in annual emissions of SO₂ of 10 million tons below 1980 levels."ⁱⁱⁱ For the year 2000 and beyond, SO₂ emissions will be capped at 8.9 million tons. Additional emissions from new facilities or incremental utilization of existing facilities will have to be offset by reductions elsewhere. Growth in fossil fuel combustion will result in higher abatement costs rather than additional pollution.

The mandated reduction to the 8.9 million-ton cap was to occur in two increments. The first to be completed by 1995 required that 263 generating units at 110 electric utility plants (mostly coal-burning) in 21 eastern and Midwest states reduce their annual emissions by 3.5 million tons.^{iv} Not only has this figure been met, but it has been exceeded as many generating plants were able to make deeper reductions and utilize or bank the additional allowances (tradable permits) allocated to them.^v By the end of year 2000, an additional 1.5 million-ton reduction will be required and a much larger number of generating units will have to restrict their sulfur emissions.

The sulfur abatement program is built around a system of SO₂ allowances that can be traded. Each electric generating unit is allocated a fixed number of allowances each year and must hold one allowance for each ton of SO₂ emitted. A generator is allowed to transfer allowances among its own facilities, buy or sell allowances on the open market or bank them for use in future years. During the first phase, the 263 affected units were given allowances permitting them an emission rate of 2.5lbs per mmBtu of heat input. In phase 2, this rate will drop to 1.2lbs per mmBtu.⁵

Generators wanting to emit more sulfur than they have permits for must find sellers with excess permits or face the prospect of paying a fine of \$2000 per ton. Generators that find themselves with a surplus of allowances can sell the permits and reap the cash benefits or bank the allowances for use or sale in a future year. The presence of a sufficient number of buyers and sellers provides an opportunity for a secondary market to emerge. Today, one can buy and sell sulfur allowances as one can buy and sell any commodity. Prices are posted on the Chicago Mercantile Exchange, and there is an active futures market for allowances with daily quotes available.

In the past, estimating the future cost of a pollution abatement program required assessment of technology costs and forecasts of how these costs might change over time. The advantage of using this methodology was its relative simplicity. The disadvantage though was the inability to factor in complex phenomena such as technological change. Today, hundreds of participants, including generators, large consumers, equipment manufacturers, fuel producers and transporters, and other competing forms of energy, all have some impact on a market for pollution control. Predicting the cost of abatement in this scenario lends itself to a more sophisticated analysis.

There are some well-defined parameters that affect emissions. First, the

⁵ Each year, some 2.8 percent of the allowances are auctioned in spot and seven-year advance auctions. Revenues from these auctions are returned to the utilities that owned the allowances. The basic purpose of these auctions is to provide liquidity into a market that was feared to be quite illiquid otherwise. As it turns out the vast majority of allowance trades are between utilities and the market has proved quite liquid. See Joskow *et al* (1998) for a further description of market statistics.

government will only be allocating 8.9 million allowances each year starting in 2001. Generators have banked a significant number of allowances, so the total impact of the cap may not be felt immediately, but, since the allowances cannot be banked indefinitely, by 2003-2004 the effect of the tighter cap will impact the market. Utilities that are unable to meet their emission cap will have to buy allowances. In the absence of any technological change, this implies higher prices for the allowances and, therefore, higher costs for dirtier utilities. Naturally, technological change, especially as it manifests itself in reduced costs for pollution abatement will affect the allowance prices. The question is whether technological change can overwhelm the price impact of the significantly tighter allowance regime.

Second, a generator's investment in scrubbers will enable it to reduce its emissions by more than 95%. With these large reductions, higher sulfur coal will become attractive, especially if this coal is substantially cheaper. While transportation costs are extremely important in the final fuel cost for generators, there is a discernible relationship between higher sulfur content and lower prices. Whether coal prices will adjust quickly to changes in the allowance prices remains to be seen. Certainly, there are vast reserves of high sulfur coal that would be accessible to many generators as improved and less expensive scrubber technology becomes available.

The problem was that when the CAAA was enacted, the capital and operating costs of new scrubbers was expected to be as high as \$466 per ton.^{vi} Actual prices turned out to be much lower. Ellerman and his colleagues at MIT found that the average price of purchasing and operating a scrubber in Phase 1 was \$286 per ton of sulfur removed and was likely to drop still further.^{vii}

The reasons for this reduction are threefold. First, scrubber technology has improved, allowing for less downtime and lower O&M costs. Second, the forces of a competitive market both among scrubber manufacturers and between them and other reduction options have put downward pressure on price. Finally, Ellerman argues that scrubbers no longer need to meet EPA's stringent operating standards. In the past, if a scrubber failed for ten to twenty hours, the plant either found itself in violation of its

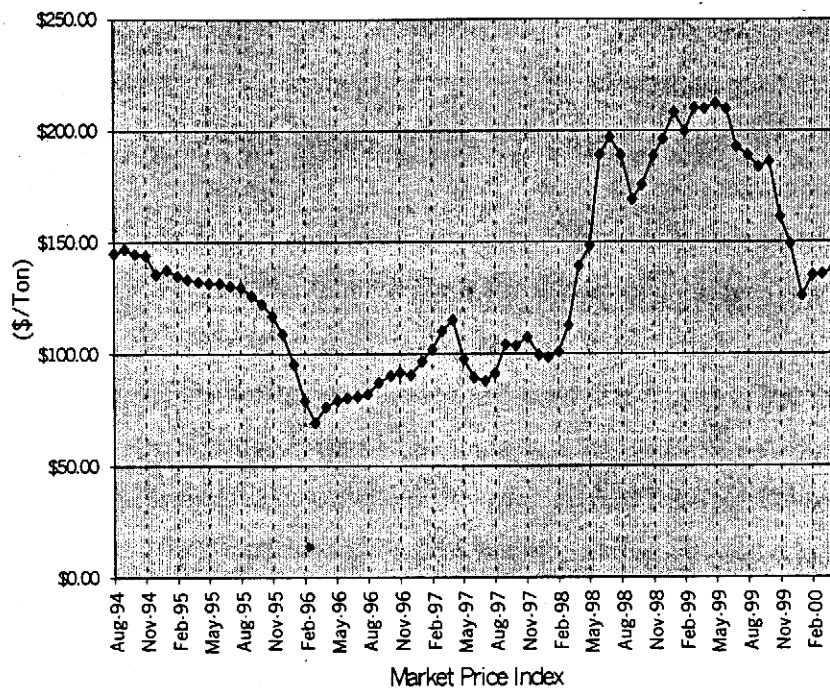
permit and liable for a fine or had to shut down until the scrubber was repaired. Under the new system, the plant simply goes into the market and buys the needed allowances and continues to operate. Hence, scrubbers do not have to be built or warranted to meet as rigid a set of specifications. This additional flexibility shows up in the marketplace as lower scrubber prices.^{viii}

Since installing a scrubber allows plants to meet both Phase I and II of the CAAA requirements, in the long run, a plant's willingness to pay for allowances is capped by the existing cost of scrubbers - roughly between \$230-\$300 per ton⁶. Given recent trends in scrubber costs this figure is declining and over the next few years could be closer to \$200-\$250 per ton. In the shorter term, generators' investments into scrubbers may be insufficient to even out the demand for allowances, leading to price blips. Further, there may be periods of panic or irrational buying, forcing allowance prices higher. But, leaving aside such short-term blips, it is unlikely that allowance prices will exceed \$250 per ton over the long run, and, for periods of time, could be significantly lower.

On the other end of the spectrum, the short-term cost of operating a scrubber is between \$65-\$85 per ton. Allowance prices below this would prompt generators to shut off their scrubbers and buy allowances instead. Again, in the very short term, there may be costs to switching scrubbers on or off, which may lead to market prices as low as \$65 per ton. This is very unlikely though, and the surge of demand at that price will make it impossible to sustain such low prices for more than a matter of months.

⁶ Ellerman, A.D. *et al* ob.cit. p.237-238

Figure 5: SO₂ Allowance Price Data



Source: Cantor Fitzgerald EBS as reported at (<http://www.cantor.com/ebs>).

As Figure 5 shows, allowance prices have ranged between \$68-\$213 per ton.^{ix} Depending upon the kind of coal that plants use, this provides a wide range for the marginal cost of sulfur emissions. For example, for a plant using coal with one-percent sulfur content and without a scrubber, this would translate to costs between 3-7 mills per kWh. With the use of a scrubber, this cost could be reduced significantly since the plant would be able to burn much higher sulfur coal. In any case, scrubber prices appear to be a long-run upper cap on the sulfur-abatement related costs from a plant using coal. Compared to the dire predictions of prices of \$600 per ton for sulfur allowances, the prices observed to date impose a relatively modest burden. The lower prices can be attributed to three factors^x:

1. enhanced availability of cleaner coal, mainly due to railroad deregulation that led to lower transportation costs from Montana and Wyoming

2. compensatory allowances, whereby the dirtiest plants were given the largest allocations of Phase I sulfur allowances as a legislative compromise necessary for passage of the CAAA
3. preemptive investments in scrubber capacity by generators that expected higher allowance prices than was justified by actual allowance prices

Allowance prices remained below \$150 per ton from 1994 through the fall of 1998, rose to over \$200 in the first half of 1999 and dropped precipitously at the end of 1999 and the beginning of 2000⁷. We do know that as Phase 2 comes into effect, the cap on sulfur emission will drop, reducing the total number of allowances. As the banked allowances are depleted, this should stimulate upward movement in price. Some of this may already be discounted and some of it may be offset by gains in equipment technology. If the price moves above \$200 per ton and creeps closer to the long run cost of scrubbers, we should see more investment in scrubbers, which will again put significant downward pressure on allowance prices. For example, if 10 GW of generation switched to scrubbers, allowances for several million tons of sulfur would become available on the market. As a result, prices would drop. The lower allowance prices will last until other generators increase their demand or alter their fuel procurement strategies. As a result, allowance prices are likely to fluctuate as they respond to investment and purchasing decisions of the several hundred generators, especially in the early years of Phase 2 implementation.

While \$250 may be the long-run marginal cost per ton of SO₂ for a plant that has heretofore failed to make significant investments in SO₂ abatement, most plants have already made some investments in sulfur abatement. These capital costs are sunk and are not included in our calculations of additional costs. Further, since we did not analyze which specific plants have made significant investments and which have not, we have

⁷ Most observers attribute the drop to the regulatory uncertainties caused by the numerous court actions brought by the industry against EPA, which made it difficult to forecast the short-term market for allowances.

also categorized the costs of operating existing pollution equipment as sunk. Admittedly, these two assumptions bias our analysis towards lower costs for coal generators, but we believe the bias to be slight.

Thus, many plants will face the choice of upgrading their existing equipment, investing in new equipment, or buying allowances. To further complicate the matter, some of the plants that invest in new equipment will have surplus allowances that can be sold, thus reducing their net incremental cost. Therefore, we believe that a more realistic high estimate of sulfur cost is \$225 and our best estimate of the incremental opportunity cost will be closer to \$175 per ton. (Costs are in 1998 dollars)

Nitrogen Oxide Controls

The Clean Air Act Amendments of 1990 (CAAA) not only regulated sulfur as a precursor to the formation of acid rain, but also called for further regulation of nitrogen oxides (NO_x). However, Congress decided to rely on traditional command and control regulation rather than market incentives to realize a 2 million-ton reduction below 1980 levels by the year 2000.

Nitrogen oxides contribute not only to the formation of acid rain, but are a major ingredient in the development of tropospheric ozone, often referred to as smog—a problem that plagues many of the large cities during the summer months. As with acid rain, smog is both a mixed and a transported pollutant. It is mixed in that it consists of hydrocarbons and nitrogen oxides that when combined with sunshine can be transformed into ozone. It is transported in that both the formation and the eventual deposition can occur many miles away from where the pollutants were emitted. There is an ongoing dispute between the states on what percent of the ozone is transported a certain distance. The downwind states claim that the volume is significantly higher than the volumes suggested by the upwind states.

Unlike sulfur, where a significant portion of the emissions originates from electricity generating stations, NO_x emissions are spread over a large number of sources: approximately 44% are from on and off-road vehicles, 26% from power plants and the

remainder from a large assortment of sources.^{xi} The reason that coal-fired generating facilities receive a disproportionate amount of the attention is that they are perceived as easier and less expensive to control.

Title IV of the CAAA requires coal-burning power plants to cut their annual NO_x emissions by 2 million tons by the year 2000. On top of this requirement, EPA has attempted to mandate additional reductions. First, EPA recently ordered an additional NO_x emission reduction of 700,000 tons in 12 states plus the District of Columbia in response to a petition from eastern states. Ohio, Indiana, Pennsylvania, and Kentucky were included in this group of 12.^{xii} Further, in July of 1997, EPA decided to lower the ambient standard for ozone from 0.12 to 0.08. This triggered a firestorm of protest and several court challenges⁸. Hence, it is not clear whether the states will have to seek reductions beyond the 2 million tons by 2000 or the extra 700,000 tons by 2003. Since technologies already exist to make these additional reductions, the issue is one of economics.

A second uncertainty is whether a marketable permit program will emerge for NO_x. Many parties, including the EPA would prefer a tradable NO_x permit regime to the present system, but at the moment no one wants to engage Congress in yet another round of Clean Air amendments. If a tradable permit regime can be implemented, the costs of NO_x reductions could drop significantly. There is a mixture of boiler types each facing different NO_x abatement costs - an ideal opportunity for an effective tradable permit program. Sources that presently have no incentive to reduce their emissions below the regulated threshold will suddenly have a profit incentive to find new ways to lower their emissions and sell their surplus permits. In the short-term, however, the extent of the cost savings is a function of the stringency of the standard. At this point in time, abatement technology to meet some of the tougher NO_x reduction targets is limited, but this will change as innovative technologies are developed and commercialized, expanding the opportunities for trading.

⁸ On March 3, 2000 the Appeals Court ruled in EPA's favor, but the Midwest Ozone Group has subsequently filed for a rehearing.

These two factors - additional reduction requirements and the establishment of a permit trading system - could have a major impact on the cost of NO_x emission reductions. Our inability to predict either their probability or their impact makes any cost estimate highly uncertain. We do have an idea of the technologies and the economics as they exist in the fall of 1999, and this information can give us a rough estimate of the status quo.

Burning low sulfur coal or installing scrubbers does not significantly reduce NO_x⁹. Thus, generators must make additional investments. Further, both coal and gas-fired plants emit NO_x. However, in this analysis, we are comparing an existing coal fleet using old, less stringent NO_x controls against new gas facilities that are required to install the "Best Available Control Technology." This abatement requirement is factored into our 3.1 cents per kWh estimate for electricity from a new gas plant, but it is not factored into the cost estimates of electricity from an existing coal plant.

The cost of NO_x abatement depends on the type of boiler being used. Most category 1 boilers-dry bottom wall fired and tangentially fired boilers-already have or are in the process of installing equipment to make measurable reductions in NO_x emissions. Category 2 boilers - cyclone and wet bottom - tend to be older, have higher emissions and will be more costly to retrofit.^{xiii}

Most states already require category 1 plants to meet an emission standard of 0.40lb NO_x/mmBtu. EPA would like to see this standard reduced to 0.15 lb NO_x/mmBtu for all boilers, but as aforementioned, there is some uncertainty whether this will occur. The difference in costs between these two scenarios is significant. The higher levels can be realized by simply installing low NO_x burners. Assuming a 60-80% capacity rate, the additional cost should be below 0.5 mills.^{xiv}

⁹ NO_x emissions are a function of flame temperature in the boiler, which in turn is a function of coal fusion temperature. Low-sulfur western coal has a lower fusion temperature and thus will generate slightly lower NO_x. (Source - Comments received from Manoj Guha, Manager Special Projects, American Electric Power on July 6, 1999)

If the 0.151b rate applies, both categories of plants will have to invest in secondary NO_x controls- primarily Selective Catalytic Reduction (SCR) or Selective Non-catalytic reduction (SNCR). These are end-of-the pipe technologies that have a high capital cost. The more units of electricity the plant produces, the less the per unit cost. Assuming that the units are used more than 50% of the time, installing either of these technologies at 1999 prices will cost between 1.25-2.3 mills per kWh for Category 1 boilers and significantly higher for Category 2 boilers-2.7-3.8 mills per kWh.

If the ultimate emission rate is somewhere between 0.4 and 0.15 lb NO_x/mmBtu, generating companies will be able to invest in low-NO_x burners in plants where the costs are high and SCR where the costs to install that technology are lower. In other words, they would develop a portfolio approach. The same is true if a true market emerges for NO_x permits.

In our analysis, we begin by assuming an NO_x abatement cost of 2 mills per kWh, but recognize that this assumes 1) that the eventual standard will be closer to 0.15 than 0.4; 2) the price of control technologies will not appreciably change and 3) trading will be limited. If these assumptions change, the price could be closer to 1.5 mills.

Reducing Particulate Emissions

The impact and timing of further reducing airborne particulates is significantly different than that of sulfur or NO_x. There is some uncertainty about whether additional reductions will be required and significant uncertainty about when they would be required. Under some scenarios, electric generators might not have to be in compliance with new federal standards, assuming they survive recent court challenges, until 2015. Therefore, a generator today will not attach a high value to an investment ten years hence, the probability of which is likely no better than 70%.

Total suspended particles is an umbrella term that covers many types of pollutants, including sulfates, ammonia, nitrates, sodium, chloride, trace metals, carbonaceous material and hydrogen ions. Some of this matter is natural in origin, while some is anthropogenic. The latter category includes fuel combustion, industrial

processes, roadway dust, soil erosion and motor vehicles. Particles can range in size. Large particles usually include those over 10 microns, while small or "fine particles" refer to those that are less than 2.5 microns. These small particles are what worries EPA. Evidence from recent epidemiological tests shows a strong correlation between increases in concentrations of fine particles and increases in mortality.^{xv} Considerable uncertainties remain. Since fine particles come in different types and different sizes, do some cause more harm to human health than others? Since almost no monitoring data exists, EPA has very little information on which areas are not in attainment with their proposed new standards and which are.

In July 1997, EPA promulgated new stricter ambient standards for PM₁₀ and new standards for PM_{2.5}. The annual average concentration of PM₁₀ was reduced from 50 to 15 ug/m³ and the 24-hour concentration from 150 to 65 ug/m³.¹⁰ To answer the uncertainties, EPA established a lengthy process. Included was a five-year effort to establish a system of 1400 monitors nationwide to collect a minimum of three years of data. EPA had hoped to begin designation of non-attainment areas by 2002. This task would not be complete before 2004. After non-attainment designations have been issued, such areas would be allowed three years to develop and submit to the EPA pollution control plans, showing how they would meet the new standards. Non-attainment areas would have up to ten years to meet the new standards with the possibility of two 1-year extensions. Thus, there are areas of the United States that would not have to meet new PM_{2.5} standards until 2014.

On May 14, 1999, The US Court of Appeals for the District of Columbia Circuit remanded the new particulate standards to EPA for further consideration.¹¹ EPA has

¹⁰ PM₁₀ and PM_{2.5} standards refer to EPA's ambient air quality standards for suspended particulate matter, whether liquid or solid, that are of sizes larger than 10µm and 2.5µm, respectively. The PM₁₀ standards state that the concentration of particulates less than 10µm cannot exceed 0.08 parts per million (ppm) over an eight hour period. The three worst observations each year can be disregarded for the purposes of compliance. The average annual concentration of these larger particles should not exceed 50µg/m³ and the concentration during any 24-hour period should not exceed 150µg/m³. The PM_{2.5} standard currently requires that the average concentration of particles larger than 2.5µm not exceed 15µg/m³ during any year. In addition, the concentration of these fine particles cannot exceed 65µg/m³ during any 24 hour period.

¹¹ This decision was widely reported in the press. See for example Warrick *et al* [1999] writing for *The Washington Post* and Glaberson [1999] writing for *The New York Times*. The actual decision was made in the case of *American Trucking Associations, Inc., Et al., V. United States Environmental*

appealed this decision, but there is now a strong probability that the timetable outlined above may be stretched even further into the future, with some uncertainty as to the scope of future regulatory action to reduce this pollutant.

If EPA is able to implement the new ambient standards, it will increase the cost of coal-fired electricity generation. At the time this paper was written, there existed no credible studies of the cost of compliance, since it is still unclear which emissions would have to be curbed. Some people argue that the focus will be on sulfates, requiring significant reductions on the SO₂ cap, while others argue that it will fall more on nitrates and other types of particles. One consulting company, in a yet to be published report, has made a rough estimate of a real cost of 5 mills per kWh with coal-burning utilities making investments in the 2007-2010 period.

Given that there is uncertainty about both the cost and the likelihood of required investments, an investor may actually be more interested in the expected cost rather than an absolute figure. Given the lengthy schedule, there will be numerous opportunities to reassess whether it is worthwhile to make the investment and whether or not there is a need to move quickly. Further, the corporate, as opposed to social, benefits of any investment in particulate reductions will not be realized for ten years. Thus, any discounted cost-benefit analysis will not favor early action under the present legislative regime. From an electric generator's perspective, both the economics and the politics clearly favor waiting.

One might argue that submicron particles are a real health risk and account for significant increases in mortality and morbidity.^{xvi} However, even under the most optimistic assumptions, abatement investments by electric generators will have to be made 8-10 years after the SO₂ and NO_x emissions requirements must be met. Given that many states allow rapid depreciation for pollution abatement investments, generators will separate their SO₂ and NO_x investment decisions from their submicron particulate abatement decisions.

Protection Agency, Case No. 97-1440, 175 F.3d 1027, United States Court of Appeals for the District of Columbia Circuit.

Estimating the price of reducing a pollutant, ten to fourteen years in the future is replete with uncertainty. What technologies will be available? What will they cost? This exercise is further complicated by the absence of an agreement on what exactly will be reduced. In this exercise, we will use a best estimate of 4 mills per kWh as the cost of particulate emission, but this estimate could be significantly higher or lower. We bound this number with a high estimate of 5 mills and a low estimate of 3.

Mercury

Most analysts have not included mercury in their base calculation of incremental pollution costs, but there is some possibility that EPA may eventually order coal-fired electricity plants to reduce their mercury emissions.

To date, EPA has focused on mercury emissions from incinerators.^{xvii} Some states have initiated unilateral action to control mercury from coal-fired power plants, but most are awaiting federal action. The major problem is that EPA has not been able to identify cost-effective mercury control technologies and, until it does, the agency is reluctant to require electric generators to reduce their emissions.¹²

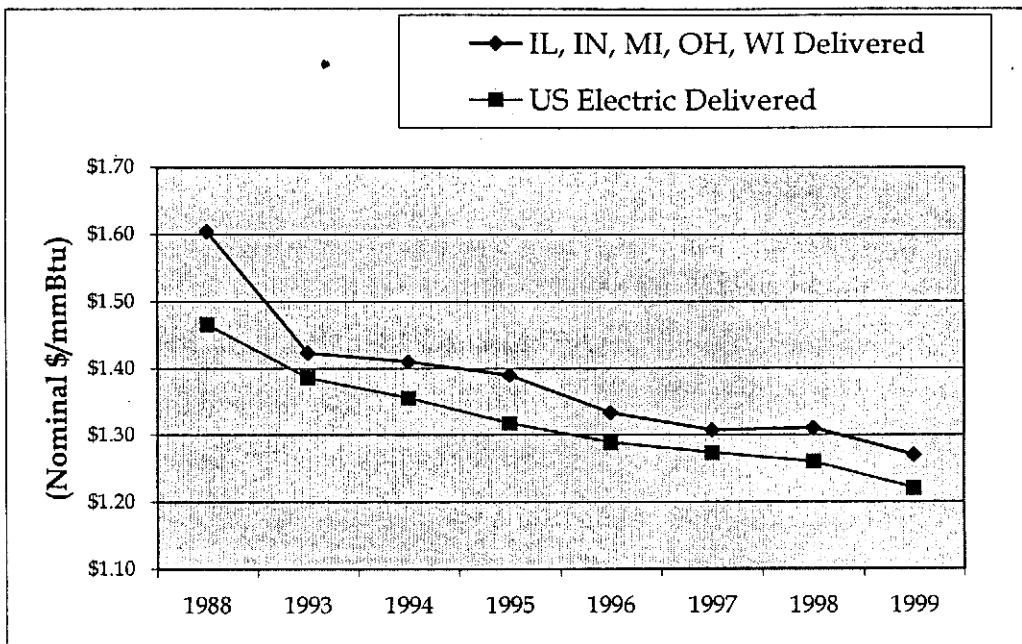
EPA recently released a new study on the costs of mercury emission reductions in combination with reducing SO₂, NO_x, and carbon dioxide emissions.^{xviii} The study concluded that reducing these pollutants would reduce mercury emissions by 34%. If mercury were reduced in isolation from these other abatement programs, the annual incremental cost would be \$1.9 billion, which would equal an approximate 1 mill per kWh cost.

¹² There is an ongoing debate as to whether forcing the electric utility industry to reduce mercury emissions will result in cost-effective health benefits. This issue is presently being studied by the National Academy of Science.

IV. NATURAL GAS COSTS

Since renewable energy technologies are still relatively expensive, the only short to mid-term competition to coal comes from natural gas. The competitive position of coal plants depends in part on the relative price of fuel. As Figure 6 shows, coal prices have been declining since 1987 both at the mine mouth and at the point of delivery. Delivered prices are close to \$1.50 per million BTUs while mine mouth prices are close to \$1.00. The consensus of opinion is that these prices are not likely to rise and under certain circumstances fall even lower.

Figure 6: Average Prices for Coal Delivered to Electric Utilities



Source: Energy Information Administration

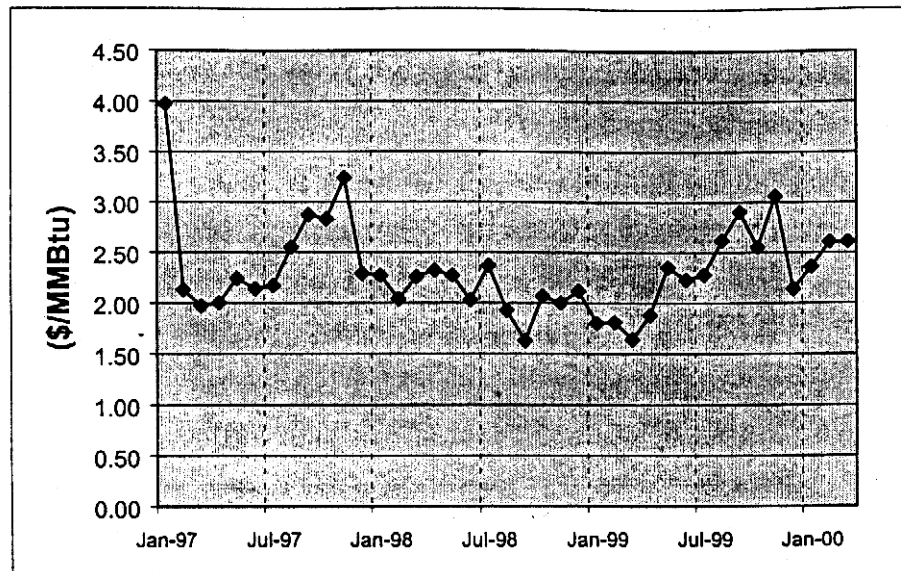
IL, IN, MI, OH, WI Delivered: **1988-1997 data:** Average Price of Coal Delivered to Electric Utilities by Census Division and State, 1988, 1993-1997, Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants;" <http://www.eia.doe.gov/cneaf/coal/cia/html/t92p01pl.html> & Fuel Quality conversion data: <http://www.eia.doe.gov/cneaf/coal/cia/html/t106p01p1.html>
1998-1999 data: <http://www.eia.doe.gov/cneaf/coal/quarterly/html/t23polpl.html>
http://www.eia.doe.gov/cneaf/coal/cia/99_special/coal99.html

If generators are to switch from coal, they will likely switch to natural gas since no other option is feasible on a large scale yet. Therefore, if we are to explore the conditions that would stimulate generators to move to gas, we need to understand a) how natural gas and coal prices are likely to change and b) the cost of switching from coal to gas. These are two different types of costs. The first refers to changes in the price the electric generator pays for fuel, while the second refers to the capital investment that will have to be made to burn the fuel. This latter cost could involve simply changing the configuration of the coal boiler and burning gas or building a new gas-fired facility. As we will show, which of these two options is selected will depend on the expectation of future natural gas prices. In addition to those costs, the investor must consider the expense of building or upgrading a spur from the main gas transmission line to the generating plant.

Natural Gas Prices

Compared to coal, natural gas prices have been volatile, fluctuating both up and down, depending on the weather, inventory levels, crude oil prices and short-term decisions by producers. Figure 7 traces prices over a two-year period at Henry Hub--a locus in northern Louisiana through which most gas bound for the Midwest flows. Prices have fluctuated dramatically during this period. Note, however, that they seem to return to the \$2.00 mmBtu level--which is significantly higher than the delivered price of coal.

Figure 7: Natural Gas Prices at Henry Hub (Weekly Averages)



Sources: **Inside F.E.R.C.'s Gas Market Report**, MARKET CENTER SPOT-GAS PRICES
<http://www.mhenergy.com/demos/gas/index.html>

In the long term, there are three factors that affect the delivered price of gas. First, the resource cost depends upon the reserves of gas and the ability to exploit the reserves economically. If more reserves become available for easier exploitation, gas prices might decrease. If, on the other hand, information becomes available that would suggest that the gas resource base is smaller, prices will increase. Second, expectations of demand affect prices in that unexpected demand growth is not built into current market prices. The third and final factor is transportation cost.

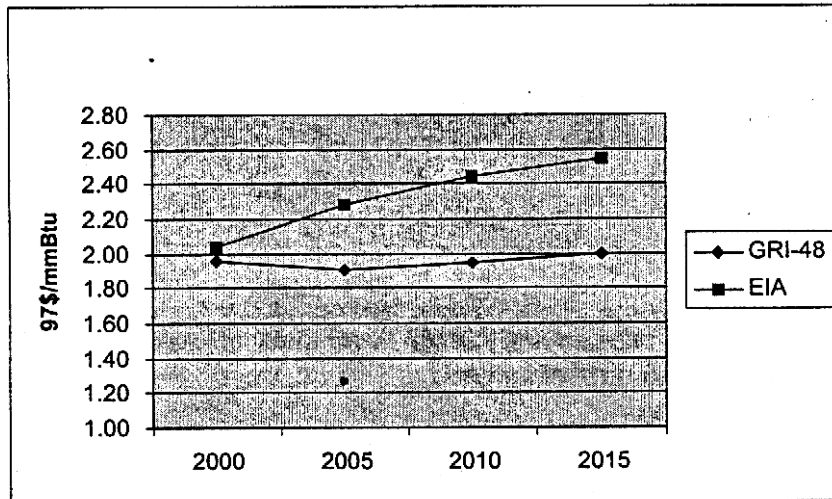
The Natural Resource Gas Base

The most widely used estimates of future gas prices come from models developed either by the Energy Information Administration or by the Gas Research Institute. Figure 8 depicts each organization's average wellhead price estimates through 2015. GRI forecasts lower prices than EIA. The difference is closely related to each organization's estimate of recoverable reserves. GRI is more optimistic than EIA, especially in the 2010-2015 period.¹³ As of January 1997, EIA was predicting that the total U.S. natural gas resource base was 1,176 trillion cubic feet (Tcf), while GRI was predicting that the size

¹³ EIA estimates are based on studies by the US Geological Survey.

was 1,793 Tcf.^{xix} These numbers are constantly changing as each organization updates their estimates. The main point is not to imply that one is necessarily more accurate than the other, only time will tell that, but rather to demonstrate that future price estimates are tied to future resource predictions.

Figure 8: Average wellhead prices



Source: EIA 1999 Annual Energy Outlook pp. 112 and GRI 1999

U.S. consumers rely on a wholesale gas market that includes Canada. Therefore, analysts must add the estimates by Canada's National Energy Board. In their most recent study, the Board estimated a resource of 720 Tcf, half of which would be found in Saskatchewan, Alberta, and Manitoba.^{xx} If this number is added to GRI's estimates, the total is 2,503 Tcf or a reserve to demand ratio of 100 years at present consumption levels.

It is important to note that both GRI and EIA predict significant increases in demand over the next fifteen years, as new power plants increasingly select gas as their preferred fuel. EIA, for example, predicts a demand of 32 Tcf by 2020 and about 28 Tcf by 2015.^{xxi} Thus, a regime to reduce carbon emissions, similar to that negotiated at Kyoto, would put further upward price pressure on gas.

In 1998, EIA completed a study of gas price trends in a carbon-constrained marketplace. The agency looked at different levels of reductions in carbon emissions and

concluded that under certain scenarios gas prices could increase to \$3.71 per mmBtu.^{xxii} These numbers are controversial because they are driven in large part by ETA's conservative estimates of the total gas resource. What is more interesting however is the dynamics of the prices over time. As the demand for gas increases, so does the price. The more the price increases the greater the level of reduction by non-utility consumers. On the one hand, gas demand, and hence price, is raised by the increased demand from electric generators, while simultaneously, prices and demand are being pushed in the opposite direction by non-utility customers who are investing in improved energy efficiency or other sources, such as renewables. Further, the natural gas supply industry is reacting to the higher prices to either increase exploration and production or invest in new technologies to allow economic access to unconventional gas supplies such as coal-bed methane. These investments will drive down prices as more supply becomes available. These factors will affect the trajectory of future gas prices and almost assure that the higher prices go in the short-run, the more they will fall later. Therefore in any given year, one might see gas prices significantly higher than a fifteen-year average that includes that year.

Analysts have never been very good at predicting future fuel prices; the dynamics almost always turn out to be more complicated than the experts foresaw. However, if one accepts the GRI resource estimates and allows for gas conversions to be made over a ten to fifteen year period, gas prices will rise. But, measured over a period of years, they should be lower than \$3.71 per mmBtu, but higher than \$2.00. In our analysis, we look at two scenarios for the wellhead price of gas in a carbon-constrained market--\$2.50 and \$3.00. (\$1998)

This choice should not be interpreted as our forecast of future gas prices since we have not undertaken any independent modeling to make such a claim. Rather, we are saying that given our review of existing studies and our conversations with modelers at

both EIA, GRI, and the Interstate Natural Gas Association of America (INGAA),¹⁴ we believe that the resource base is larger than predicted by USGS in 1998. Hence, we estimate that the probability of prices between \$2.50 and \$3.00 is greater than the probability of a lower or higher range. However, we recognize that prices could be higher than \$3.00 per mmBtu, as EIA suggests, or lower than \$2.50, especially if the resource base is larger than predicted or the technology to access unconventional sources of gas improves dramatically. Further, in the short-term, gas prices could rise significantly above \$3.00 per mmBtu. But, we believe that competition will stimulate new supply and reduce demand, pushing the price back to a long-run equilibrium, which should be close to \$3.00 per mmBtu. However, we admit that substantial uncertainty surrounds this estimate.

Gas Transmission

To move the gas from Henry Hub, or whatever the point of purchase, requires access to pipeline capacity. At the moment, most of the pipelines feeding the Midwest are operating close to capacity. (see Table 2 and 3). As gas demand increases, additional capacity will have to be built. Under a business as usual scenario, more than 1.5 billion cubic feet of additional capacity will be needed for the Midwest states over the period 1997-2001.

Table 2: Pipeline Capacity into the Midwest

MMcf/day	Central	Northeast	Southeast	Canada	Total
Entering Capacity (12/31/98)	10,913	2,038	9,821	3,234	26,006
Entering Capacity (12/31/96)	9,879	2,038	9,821	3,049	24,787
Usage rate as of 12/31/96	78%	45%	82%	85%	78%

Source: EIA: Natural Gas 1998 - Issues and Trends; EIA: Deliverability on the interstate Natural Gas Pipeline System.

¹⁴ Consultants to INGAA informed us that these studies show that gas prices in a carbon-constrained world should be between \$2.10 and \$2.70 (interviews with Energy and Environmental Analysis, Inc. (EEA) consultants Bruce Henning, Kevin Petak, and Joel Bluestein for INGAA, July 9, 1999).

Table 3. Projected Capacity entering the Midwest

	1997	1998	1999	2000	2001	2010
bcf/Yr	7,967	8,142	8,519	9,048	9,531	9,531
Usage Rate	67%	73%	72%	69%	68%	NA

Source: EIA^{xxiii}

If seventy percent of the coal-fired generation in ECAR and MAIN are shifted to natural gas over a 10-year period each year, the pipeline industry would have to build capacity to transport between 370-497 billion cubic feet per day. The larger number assumes that gas is burned in coal boilers (which are less efficient) while the former assumes that either new plants are built or existing plants are re-powered. (Table 3 contains the assumptions built into this calculation.) It is worth noting that annual pipeline increases into the Midwest have been averaging 360 billion cubic feet. Thus, the required additions look to be achievable without significantly higher costs.

This perception is confirmed by a recent study completed for the Interstate Natural Gas Association of America that assessed the pipeline and infrastructure needs in a carbon constrained regime.^{xxiv} Specifically it looked at the needs if natural gas demand were to reach 30Tcf per year. Their study concluded that between \$2.3 and \$2.5 billion would have to be spent each year to build the needed infrastructure with more than half of it earmarked for the Midwest and Northeast states. While this figure is high, the average annual expenditure over the past fifteen years has been \$2.3 billion.^{xxv} Hence, this increase in transmission capacity seems manageable.

There are three other factors worth noting. Table 4 compares five gas transportation corridors. The first fact that jumps out is new pipeline construction in these five corridors has reduced transportation costs in three of the five corridors and kept them fairly equal in the other two. Second, the volume of gas moved through the pipeline as a percentage of a pipeline's total capacity to move gas--the pipeline's load factor-- plays a very important role in determining rates. For example, if a pipeline from Appalachia to Boston is operating at 100% load factor as opposed to 40%, its tariff would be almost 45% lower per unit of gas transported.

Table 4. Range of Maximum Transportation Rates for Corridors with Multiple Routes, 1991 and 1994 (1998 \$)

Supply to Market Corridors	100% Load Factor		40% Load Factor	
	1991	1994	1991	1994
Gulf Coast to Boston	0.73	0.13	1.26	0.41
Appalachia to Boston	0.44	0.22	0.82	0.40
Canada to Boston	0.33	0.34	0.98	0.83
Gulf Coast to NY	0.38	0.41	0.65	1.06
Gulf Coast to Detroit	0.60	0.28	1.04	0.66

Source: EIA, Energy Policy Act Transportation Study: Interim Report on Natural Gas Flows and Rates Chapter4 Table 10.

New pipeline capacity increases competition between pipelines and this tends to lower prices. Further new lines usually operate more efficiently than older ones and in regions, such as the Midwest, where there is considerable gas on gas competition, new lines actually can serve as a price cap on the tariffs charged by old lines.

In summary, while in a carbon constrained world there will be significant demand for new pipeline construction into the Midwest, we expect that this expansion has as good a chance to decrease pipeline rates as it has to increase them. Hence for the purpose of this analysis, we are assuming no change in gas transmission rates.

Fuel Switching

If Midwest generators are to weigh the cost of switching to gas, they must consider both their additional fuel costs and the capital cost of switching. At a minimum, these include the costs of purchasing and installing the equipment necessary to allow them to burn gas and the cost of a pipeline spur to move the gas from the pipeline to the plant.

It is possible to burn natural gas in a coal-fired facility for a cost ranging from \$70 to \$125 per kilowatt^{xxvi}, depending on the age of the plant and the type of boiler. In the

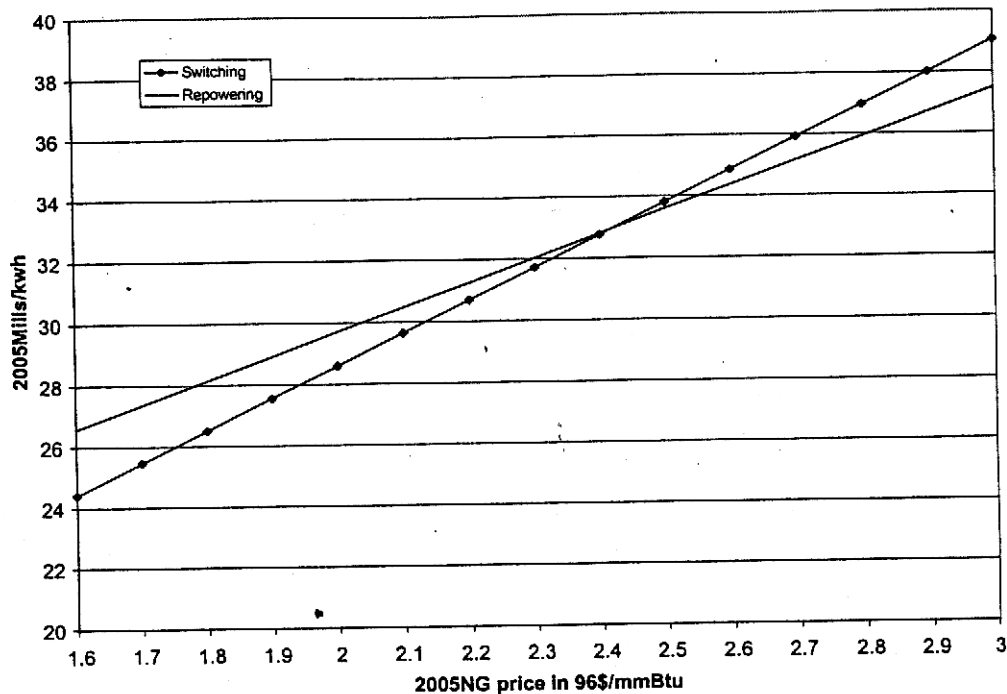
simplest case, the generator would need to install a gas compressor and replace the water pipes inside the boiler.

The problem is that the heat rate for generating power remains at the same high level as when it burned coal. In fact, there is a slight loss of efficiency compared with the coal plant--usually 2-4 percent. Thus, an average existing coal plant, burning gas will have a heat rate above 10,200 Btu/kWh. While a new gas facility could have a heat rate below 7000.

The other options are to build a new gas facility or re-power an existing one. The latter involves gutting the inside of a coal facility and installing a new gas unit. The developer is able to avoid buying a new site and is able to utilize some of the existing infrastructure. The downside is that the existing coal facility is taken out of commission permanently and for the two-three year construction period the generator loses the capacity. Thus, we believe that most generators will opt to build a new facility rather than re-power an existing one. In fact, even when the gas facility comes on-line, it is likely that the generator will mothball rather than completely retire the coal plant. Thus if there is an unexpected rise in demand, the generator could restart the mothballed facility.

A new gas facility will have a capital cost of approximately \$550 per kilowatt. At today's wellhead gas prices of \$2.00 and assuming a weighted cost of capital of 12.75 percent, a generator could build and operate a new combined cycle gas plant for 30-31 mills per kWh.

Figure 9: Average Cost of Switching and Repowering Coal Plants



In Figure 9, we compare the costs of retrofitting a coal facility to burn gas and building a new power plant. At a gas price above \$2.4/mmBtu, an investor will favor the latter option. In a carbon constrained scenario, gas prices are likely to be at this level or higher, thus generators who choose to switch away from coal, will prefer to build new gas facilities as opposed to simply switching fuels and burning gas in a coal boiler. If gas prices are thought to be significantly lower than \$2.4/mmBtu, some coal-fired generators might choose to simply burn gas in their existing coal facility. But federal and state environmental regulators are likely to use their permitting powers to lock in the use of gas, preventing the generator from moving back and forth from coal to gas. Hence, the generator is left burning expensive gas in an inefficient facility, while trying to remain competitive in the wholesale market for electricity.

Since gas prices in a carbon constrained world are expected to be closer to \$2.50 per mcf than \$2.00, existing coal-fired plants will opt to build new gas facilities rather than burning gas in an existing coal facility.

Distribution Infrastructure

Some installed coal capacity is configured to use natural gas as a secondary fuel and thus already is connected directly to a major gas transmission line. Others have small connections to feed the stabilization flame. In most cases, however, a new line will have to be built from the gas pipeline to the plant. The cost of installing a spur line is a function of the distance to be covered and the diameter of the pipe. Table 5 provides a breakdown of the costs. A ten-mile connection using a 16-inch diameter pipe will cost \$3.5 million. For a 500 MW plant, amortizing the investment over ten years, the incremental cost will be 0.19 mills or one fifth of one cent. Thus if most coal plants in MAIN and ECAR are within twenty miles of a pipeline, the expense of building an interconnecting spur will be very small.

Table 5: Installation Cost of New Spur Lines

Pipeline Diameter in Inches	Cost in Million \$ Per Mile
20	0.6
16	0.35
12	0.2
8	0.15

Source: Oil and Gas Journal (August 31st 98)

Using ETA's Geographic Information System-Natural Gas software, we looked at the distance between major interstate gas pipelines in Ohio, Indiana, Michigan, and Illinois and existing coal facilities. Tables 6 and 7 summarize our findings. Most coal facilities in these three states are within ten miles of a major pipeline. Assuming that generators either switch their coal facilities to gas or use the same sites to build a gas facility, the cost of linking existing coal sites with a pipeline will be low. If they decide to build on a new site, they will weigh the distance from the nearest pipeline.

Table 6: Average Distance between Plants and Major Pipelines

Distance in Miles	Ohio	Indiana	Illinois	Michigan
Arithmetic Average	4.1	7.5	7.4	4.5
Weighted Average	3.1	6.9	9.4	6.5

*Weighted by plant capacity

Table 7: Distribution of Distance between Plants and Major Pipelines

(For Ohio, Indiana, Illinois, and Michigan)

Distance from closest pipeline	Less than 5 miles	5 to 10 miles	10 to 20	More than 20 miles
Share of total	61.9%	22.6%	10.7%	4.8%

V. THE IMPACT OF CARBON TAXES

In previous sections we have considered the effects of various pollution charges on the operation of coal plants. In this section we formally consider the increases in cost as a result of including pollution costs. We show that including conventional pollution cost increases the cost of electricity from coal plants substantially, but is insufficient to make these plants less competitive than new gas plants. We start by first estimating the cost of coal generation and the cost of controlling sulfur dioxide, NO_x, particulates, and mercury emissions. A cost gap remains between the all-inclusive cost of coal generation and the cost of new gas generation. We then consider what magnitude of carbon related levies would be required to make gas plants competitive compared to coal plants. We test for the sensitivity of the expected carbon penalties to changes in the cost of conventional pollution abatement and changes in gas prices.

The estimates of the cost of abating conventional pollution suggest that it will be possible for the vast majority of coal plants in the Midwest to meet tighter conventional air pollution standards without facing a significant threat from new gas plants. In almost every case, the investments that generators will have to make to comply with new conventional pollution requirements will be a more attractive option than investing in new gas capacity. For the most part, tighter standards for conventional pollution may mean more expensive electricity and cleaner air, but would do little to displace coal plants from their dispatch order. In fact, as more gas plants are built in the Midwest to meet increased demand for peaking capacity, existing coal plants will be used more as they move up the order in which plants are dispatched. Unless some unprecedented changes occur in coal or gas prices, or there is a movement towards still tighter air pollution standards, the current projections of low coal prices and moderate gas prices do not, by themselves, warrant a change from coal to gas. This perception in favor of coal is further reinforced by the knowledge that any move from coal to gas would likely be irreversible. The EPA would be extremely reluctant to let generators switch back from gas to coal.

However, there is a strong likelihood that, at some point in time, some form of carbon reduction regime may be put into place, thus altering the competitiveness of coal plants. Since generating electricity from coal is more carbon intensive compared to gas, any carbon regime that is based directly upon carbon emissions, whether it is in the form of taxes or tradable allowances, will have a disproportionate impact on coal. Hence, policy makers have focused on estimating the size of the carbon penalty that will have to be imposed in order to reduce a particular level of emissions.

We attempt to estimate the dollar value of this carbon penalty. In order to calculate conservative estimates, we make the following assumptions for each of the categories of conventional pollutants:

Sulfur: Existing investments into scrubbers are sunk, and therefore do not matter in decisions going forward. The cost of running the scrubbers is ignored, even though it is a significant percentage of the total cost of generation. The only cost that we consider is the marginal cost of actual emissions after scrubbing away part of the total sulfur content of the coal. The marginal cost of actual emissions is equal to the cost of sulfur permits. For generators that do not own sulfur permits, this amounts to the cost of buying them. For generators that do own sulfur permits, emissions amount to a lost opportunity for selling the permits and, thus, the effect is equal. Since data on actual sulfur emissions are available for each unit, we are able to estimate the marginal cost (MC) of emissions at a unit-specific level.

$$\text{MC of Sulfur Emissions} = \frac{\text{Annual Sulfur Emissions} \times \text{Allowance Price}}{\text{Total Annual Generation}}$$

We assume that the cost of sulfur allowances is likely to be about \$175 per ton. This cost translates into a different cost for each plant, depending upon the type of scrubbers installed and the quality of coal used. For example, for a plant presently using 1% sulfur coal with no scrubbers this cost would translate into 6 mills/kWh (assuming average heat rate and fuel heat content). For a plant with 4% sulfur coal, this cost would amount to about 24 mills/kWh. However, since almost every plant has some form of scrubbers installed, the net cost of sulfur emissions is much lower. The median marginal

cost of sulfur emissions at an allowance price of \$175 per ton is about 3 mills/kWh, though wide disparities exist between plants.

For upper and lower bounds of emissions costs we assume sulfur permit prices of \$225 per ton and \$75 per ton. These prices reflect scenarios discussed earlier. The cost of emerging scrubber technology will make it difficult for permit prices to stay above \$225 per ton and there is a prospect that rapid technological development might decrease the cost of emissions from the current levels. At \$225 per ton the median cost of sulfur emissions would be 3.6 mills/kWh, while at \$75 per ton the cost would be 1.3 mill/kWh.

NO_x: Unlike sulfur, accounting for NO_x emissions for each unit is not possible since data at the unit level is not available. Neither is there a market for NO_x emissions permits that would allow us to get a market-based benchmark for the cost of NO_x abatement. Instead, we have to rely on average numbers for the cost of abatement for NO_x emissions. We realize that wide disparities in the cost of NO_x abatement exist, depending upon the kind of control technology already in place, the type of boilers and the type of coal used. However, since we are unable to estimate the effect of these differences, we use an average cost of 2 mills/kWh. For the upper and lower bounds we assume costs of 4 mills/kWh and 1.5 mills/kWh. These numbers are in line with previous studies on the cost of NO_x emissions. It is important to point out that the adoption of an NO_x trading program could significantly reduce these costs. Certainly, the 4 mills/kWh high estimate would be too high, and even the 2 mill figure would likely be an overestimation.

Particulates: As in the case of NO_x emissions, we cannot estimate the cost of particulate emissions at the plant level. We use an average cost of 4 mills/kWh and upper and lower bounds of 5 mills/kWh and 3 mills/kWh. Because particulate emission requirements, assuming they are eventually upheld, do not have to be met until 2012-2014, these numbers are very conservative.

Mercury: The cost of mercury emissions is relatively small. We assume that the cost is 1 mill/kWh in the base case and that the cost does not vary much.

Total cost of conventional pollution : Thus the total cost of conventional pollution in the base case is 10 mills/kWh, whereas in the upper and lower bounds the cost is 13.6 mills/kWh and 6.8 mills/kWh.

We add these costs to the fuel cost for each unit, which can be computed from the fuel price and the reported heat rate for the unit and a 2mills/kWh cost for variable operation and maintenance costs. Figure 10 shows the fuel cost curve for the Midwestern plants. Figure 11 shows our best estimate of the cost of generation when all proposed emission abatement costs are added.

Figures 12 and 13 show the lower and upper estimates for the cost of generation. With the lower estimates, almost all of the existing coal plants in the Midwest will be less expensive to operate than building a gas-fired generating facility. However, with the upper estimates of the cost of air pollution abatement, roughly one quarter of the generation is more expensive than the cost of generation from new gas plants. That is if one believes that it will cost 13.6 mills per kWh or more, the economics should lead Midwest generators to retire 25 percent of their coal capacity and replace it with gas-fired generators.

Figure 10: 1998 Fuel Cost Curve for Coal Plants in ECAR and MAIN

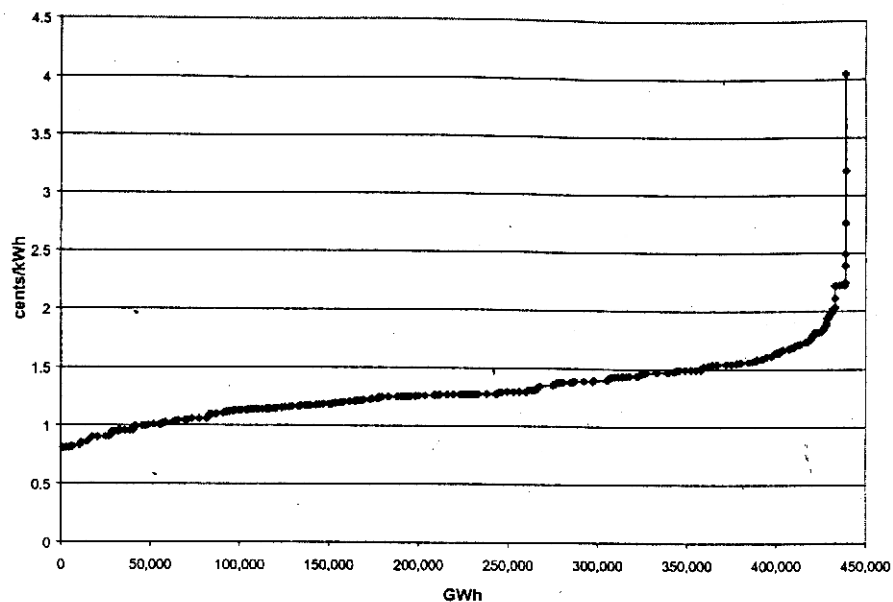


Figure 11: Best Estimates of Future Cost of Coal Generation, Including All Costs

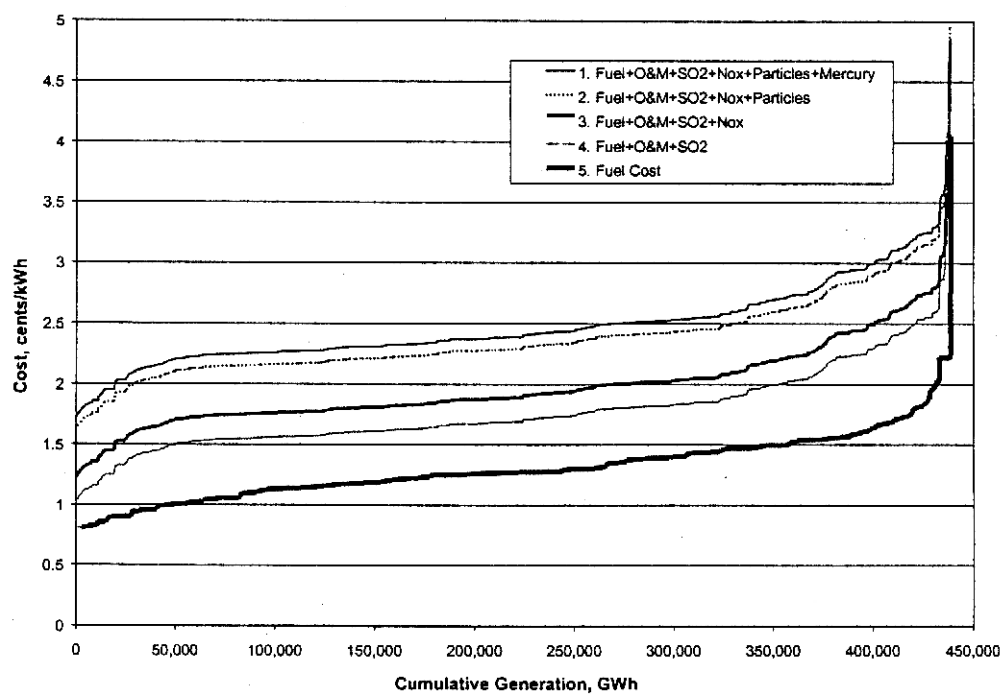


Figure 12: Lower Estimates for Cost of Coal Generation Including All Costs

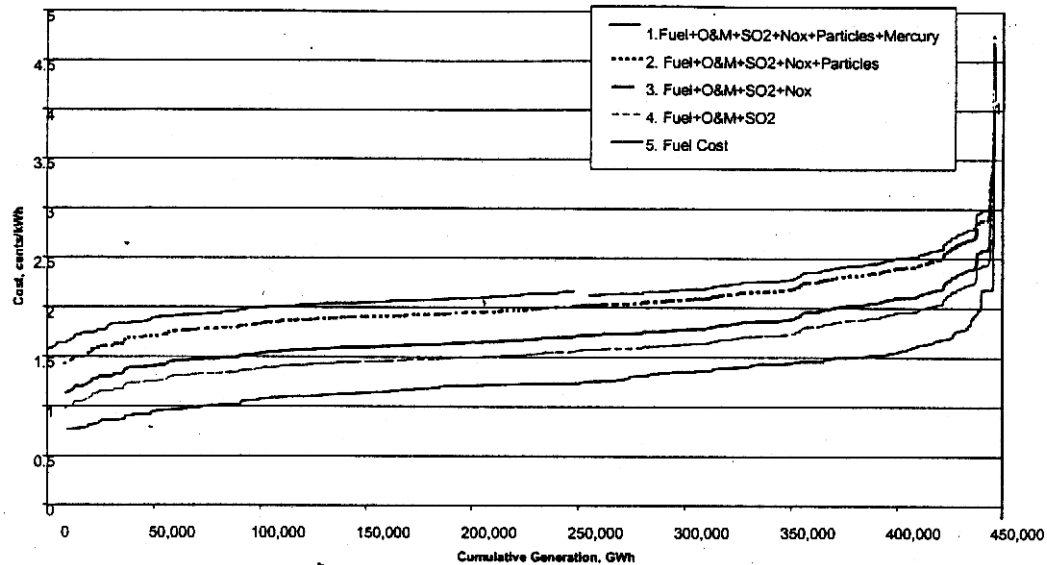
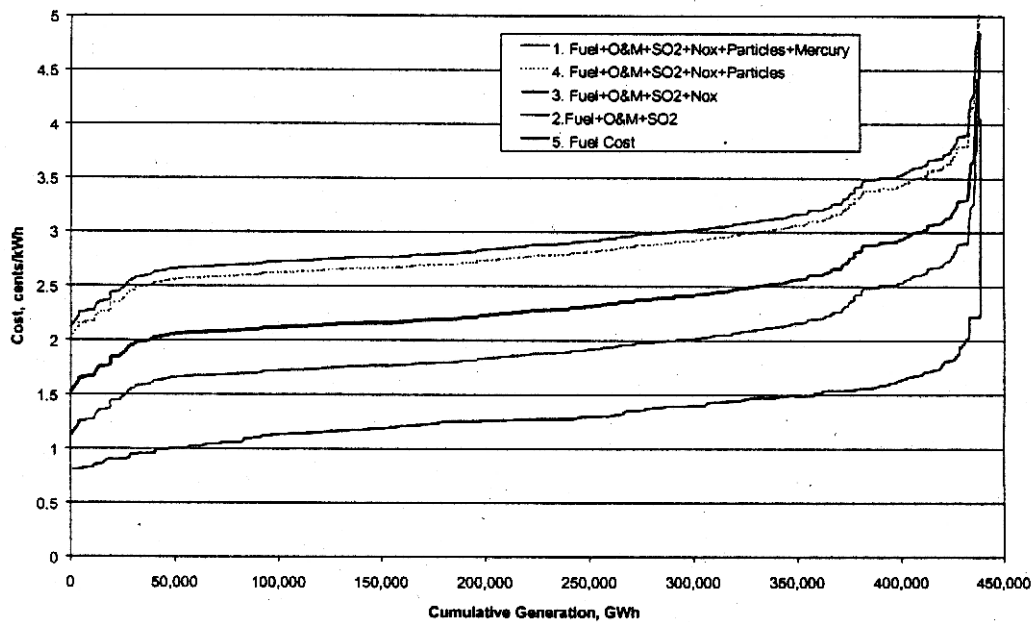


Figure 13: Upper Estimates of Cost of Coal Generation Including All Costs



In computing the upper and lower bounds for costs, we need also to account for the different estimates of natural gas prices. As stated earlier, we expect the gas price to be no lower than \$2 per mmBtu and no higher than \$3 per mmBtu, which roughly corresponds to costs for gas generation of about 3.1 cents/kWh and 3.8 cents/kWh

respectively. We must now integrate these estimates with the pollution abatement cost estimates.

For our base case, we assume a gas price of \$2.5 per mmBtu, corresponding to a cost of generation of about 3.5 cents per kWh. To compute our upper cost estimate of generation from Midwest coal-fired facilities, we take our very high pollution abatement costs estimate and our lowest estimate of gas prices of \$2 per mmBtu. In this high scenario, we are comparing gas-fired generation of 3.1 cents per kWh against coal plants that will have an average cost between 2.6-2.8 to operate (See supply curve in Fig. 13). Our most favorable coal scenario is calculated in a similar fashion. We combine the lower bound scenario for coal-fired facilities (Fig. 12), to the highest gas prices of \$3 per mmBtu, or 3.8 cents/kWh.

The question now is one of interpreting the figures to derive what the effect of a carbon penalty might be. Clearly, any additional cost related to carbon emissions will make generation from coal more expensive. The EIA estimates that, on average, carbon emissions from coal plants are about 235 kg/MWh, whereas emissions from conventional (F-Frame) combined cycle gas turbines is 113 kg/MWh. If we use numbers for advanced (G- or H-Frame) combined cycles turbines instead carbon emissions are about 90 kg/kWh.^{xxvii} Again, we conservatively estimate that the difference in carbon emissions between coal and gas is about 120 kg/MWh. With these estimates, imposing a carbon penalty of \$10 per ton would impose a differential cost of 1.2 mills/kWh. That is, the cost of burning coal will rise 1.2 mills per kWh more than that cost of burning gas.¹⁵ This implies, for example, that a \$60 per ton carbon penalty would mean an incremental cost for a coal plant as compared with a gas plant of 7.2-8.7 mills/kWh.

Our approach is to estimate the percentage of existing coal-fired capacity that would become less competitive than new gas-fired capacity based upon the imposition of rising carbon costs or penalties. We estimate this by taking the difference between the cost of generation from new gas capacity, approximately 3.1 cents/kWh in the fall of

¹⁵ If, instead, we make the comparison with advanced turbines the differential burden on coal plants is about 1.45 mills/kWh.

1999, and our estimates of the cost of coal-fired electricity generation after conventional pollution abatement costs have been added (Figure 10) and then adding various carbon penalties. Table 8 presents our base case estimates.

Table 8: Conversion of Coal Plants to Gas: Base Case

Carbon Penalty	Expected Conversion
\$ per ton	
0	4.0
10	7.0
20	13.1
30	15.8
40	23.1
50	40.7
60	60.7
70	88.9
80	94.1
90	97.2
100	-100

The results suggest that a carbon penalty of \$100 per ton would be sufficient to make almost all of the coal capacity in the Midwest less competitive than new gas plants. Further, the chart implies that a carbon penalty of somewhere between \$60-70 per ton will be sufficient to replace two-thirds of the coal capacity. We realize that this table significantly oversimplifies the dynamics of a carbon-constrained marketplace. As the carbon penalty increases and more generators switch from coal to gas, coal production and transportation prices will drop still further, as will the price of pollution abatement, since there will be a large short-term incentive to keep the market for coal alive. Thus, the dynamics of conversion will not be linear as this table implies. At carbon penalties above \$50 per ton, coal producers and the railroads will reduce their price still further. Some rail routes and some coal mines will be forced to shut down, but the price of the remaining coal will fall. For conversions at the low end of the chart, coal price changes will not make a large difference. But, for conversion levels around 65% of the Midwest fleet, coal prices could be driven to very low levels, pushing the carbon penalty needed to induce conversion higher than the numbers in Table 8. For example, Table 8 implies that

the \$10 dollar increase in the carbon penalty from \$60 to \$70 per ton will stimulate an increase in conversions away from coal of an increment of 28% of the Midwest coal capacity (60.7 to 88.9% of the capacity). In the short run, the actual increase in carbon prices needed to convert these residual coal facilities (the plants at the low cost end of the supply curve) could be \$25-50 higher than Table 8 implies, especially in the initial years when carbon regulations are introduced.¹⁶ This premium will fall over time as the market will adjust. The eventual economics of some of the low cost coal-fired plants depend upon factors beyond the scope of this study. Some of these plants may have adaptive capabilities that we have not considered. The non-linear correlation at the higher end of the supply curve for coal conversions is a topic worthy of additional analysis. However, even with a non-linear correlation between increases in carbon and expected conversions, Table 8 implies that a significant percent of the Midwest coal-fired generation will retire and be replaced by gas at a carbon penalty of \$100 per ton.

In order to check for sensitivity, we built scenarios for the upper and lower bounds of conversion. In the upper bound scenario, the cost of coal generation is estimated at its maximum and the price of natural gas at its minimum. We assume the cost of conventional pollution at 13.6 mills/kWh while the cost of gas generation is 3.1 cents/kWh. With these assumptions, we get the following maximum percentages of conversion at different carbon penalties. (See Table 5)

Table 9: Conversion of Coal Plants: Most Favorable Gas Scenario

Carbon Penalty	Maximum Conversion
\$ per ton	%
0	25.0
10	39.8
20	56.3
30	87.8
40	93.2
50	95.7
60	~100

¹⁶ Our suspicion is that this "premium" is likely to be closer to \$25 than \$50, but we have used a broad range, since we have not done the plant specific analysis to narrow the gap. Unless there are significant developments in coal burning technologies, this premium will decrease, as investors will slowly divert their funds to other opportunities with a higher return.

The results here indicate that a carbon penalty of \$60 per ton would be sufficient to achieve almost total conversion of coal plants. Compared to the price range of \$60-70 per ton for achieving two-thirds conversion, we now have a price range of \$20-30 per ton for the same level of conversion.

Finally, Table 10 gives the results from the lower bound scenario where the cost of conventional pollution abatement from coal is estimated at 6.8 mills/kWh and the cost of gas generation is assumed to be 3.8 cents/kWh.

Table 10: Conversion of Coal Plants: Most Favorable Coal Scenario

Carbon Penalty	Minimum Conversion
\$ per ton	%
20	~0
30	0.1
40	0.3
50	0.4
60	0.5
70	1.9
80	2.2
90	4.9
100	7.2
110	13.7
120	21.0
130	30.5
140	49.3
150	76.7
160	90.0

The results of the lower bound scenario indicate that the cost of converting two-thirds of the coal fleet could be much higher. This scenario combines the best possible scenario of rapid technological change in pollution control equipment and with high gas price estimates.

Recent increases in natural gas prices have led some experts to suggest that long-term gas prices may be significantly higher than \$3.00. While we would caution against

assuming that the future will resemble the present or the immediate past, we admit that there are conditions that could drive gas prices beyond the \$3.00 per mcf in our high cost scenario and certainly beyond the \$2.50 estimate in our base case. Let us assume that long-term gas prices are \$3.50 per mcf, using the figures in Table 8, one would add \$35.00 to our carbon estimates. Thus, the carbon penalty needed to reach the 65% conversion level increases to at least \$95-\$110 per ton. As mentioned earlier, we suspect that in the short run a premium of \$25-\$50 above these figures will be needed to convert the residual coal plants, but this premium will fall fairly steeply over time. If you believe that \$3.50 is still too low and would prefer \$4.00 per mcf, then add an additional \$17.50 to the carbon penalty estimate.

Because of the strong demand for gas-fired combined cycle plants, capital costs for this equipment has increased. Further O&M costs on the new high-efficiency turbines have been higher than expected. These two factors have increased the cost of building and operating a gas fired plant. Problems, either with the characteristics of bottlenecks in production capacity or technical start-up difficulties with new technologies, are usually resolved in the marketplace. Thus, we do not expect these two factors to significantly change our estimates.

We conclude from this analysis that the carbon penalties required to induce substantial switching from coal to gas is less than what many studies have indicated. Our base case contains realistic assumptions of both conventional pollution costs and the cost of gas generation and indicates a fairly modest carbon penalty. We suggest that policy makers should work on the premise that carbon penalties of \$60-100 per ton, which raise the price of electricity by about \$15-25 per MWh, are reasonable assumptions. The increase in the price of electricity of \$15-25 per MWh has to be seen in the light of today's average retail prices of about \$75 per MWh in the Midwest (EIA). Increases in the costs to reduce conventional pollutants could raise the retail price by approximately 1 cent per kWh to 8.5 cents (\$1998) and the carbon penalty will add another 15-22% to this cost, resulting in a price of 10-10.7 cents per kWh - a price still lower than that paid by many electricity consumers in the Northeast.

In this paper, we have deliberately not said anything about the timing of the conversion. Clearly, the effect carbon penalties may have on electricity prices depends upon numerous other factors, including when and how they are applied. Our assumption has been that generators will make decisions on a composite strategy keeping in mind the various pollution costs that may be imposed upon them, either for conventional pollution or for carbon. However, this assumption can be easily negated if the pollution regulations are applied piecemeal.

For example, if generators were to install equipment to meet sulfur, NO_x, particulates and mercury emissions regulations and then be faced with new requirements to reduce carbon, they would have large investments that would not be fully amortized. Further, since these investments are sunk, the marginal cost of carbon abatement would be much higher than if it had been part of an integrated strategy to reduce both conventional pollutants and carbon. Generators would compare only the operating costs of the conventional pollution control equipment with the cost of switching to gas. Such a comparison would turn out quite unfavorably for carbon controls. In other words, the industry would argue that it had a major stranded cost problem that would have to be reduced or eliminated as part of any negotiated agreement to lower particulate or CO₂ emissions.

In order to avoid just such a scenario, which will lock in coal plants, albeit with cleaner technology, it is preferable to take a holistic view of pollution control and devise early action credits for carbon and particulate controls. It is equally important for the Administration to articulate a long term strategy for pollution control so that generators take into account all proposed regulations at once rather than deal with them one at a time. Such a strategy must involve more than exhortations. Financial incentives that will alter a generator's economic self-interest are essential if more than a token number of Midwest generators are to contemplate switching to gas over the next ten years. However, those incentives must target precisely the actions desired or they will prove to be inefficient. In this instance, the desired action will be accelerated retirement of older and dirtier coal fired generation, and more rapid construction of new and cleaner gas-fired facilities. Incentives for fuel switching - burning gas in coal-fired boilers - should be

avoided since they will result in switching the newer coal facilities as opposed to the older coal plants which are dirtier and less efficient, and they will increase natural gas consumption, putting still greater upward pressure on gas prices.

We would also urge policy makers to consider two additional short-term actions. First, the government should set an early date, preferably in 2000 or 2001, for determining baseline carbon emissions. Otherwise, generators will have a disincentive to make any carbon reductions for fear of reducing their baseline from which the government will eventually expect reductions. Second, proposals for an integrated approach to reduce emissions of SO₂, NO_x, particles, and carbon dioxide simultaneously should be seriously explored. EPA has attempted to establish a voluntary comprehensive approach to air pollution reduction, and more recently, select environmental NGOs and electric generators have held preliminary talks. In addition, several bills have been filed in Congress to establish pollution limits for NO_x, SO₂, and CO₂, and Mercury - reductions that would have the indirect effect of reducing carbon dioxide emissions.^{xxviii} But these initiatives have collapsed, in part due to distrust among the government, the generators, and the environmental NGOs, in part because of the inflexibilities in the law, and in part to overreaching by each party. Admittedly, the political hurdles facing such an approach are significant, but the environmental and economic benefits could be substantial and, under certain scenarios, the economics could be equally valuable.

This paper has attempted to identify the factors and the assumptions that will shape the economics of converting the Midwest electric generating fleet away from coal. We realize there is enormous uncertainty around many of these assumptions and we have attempted to identify and characterize these uncertainties. We do not advocate a particular level of coal conversion, but rather attempt to identify what it would cost to realize whatever level of conversion desired by policy makers. In all likelihood, we have raised more questions than we have answered, but we hope we have laid out a framework for thinking about these dynamics and will stimulate others to take this analysis several steps beyond where we have left it.

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- ^{xxv} *Ibid.*
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^{xxvii} EIA. 1998. "Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity", EIA Report #: SR/OIAF/9S-03. Table 16: "Cost and Performance Characteristics of New Fossil, Renewable, and Nuclear Generating Technologies." Washington D.C.: U.S. DOE.

^{xxviii} U.S. Senate. *Clean Energy Act of 1999*. 106th Congress. 1st Session, S. 1369. (1999 S. 1369; 106 S. 1369)