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Folder Title:
Clean Air Act - Carbon Dioxide Effects

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4/25/91

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Received (YY/MM/DD) 1/1Name of Correspondent: Don Dudek☐ MI Mail Report

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Subject: Environmental Defense Fund
CO₂ and SO₂ : Consistent Policy
Making in a Greenhouse

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	<u>Quat17</u>	Referral Note:	<u>91 04/24</u>			<u>91 05/04</u>
	<u>Quator</u>	Referral Note:	<u>ATTN: EYI</u>			<u>1/1</u>
	<u>Qugray</u>	Referral Note:	<u>1/1</u>			<u>1/1</u>
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Sub. P. 126

CAA-CO₂ effects



Environmental Defense Fund

257 Park Avenue South, New York, NY 10010

NEWS RELEASE

For Release Thursday,
January 11, 1990

Dan Dudek, Alice LeBlanc 212 505-2100
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EDF SAYS SOLVING ACID RAIN WILL REDUCE GREENHOUSE HEAT *Report says market-based controls have dual benefits*

WASHINGTON -- Adopting market-based controls on the pollutants that cause acid rain also will help ease the greenhouse effect, according to a report released Thursday by the Environmental Defense Fund.

"The United States does not have to wait for grand international agreements to begin solving the global warming problem," said Dr. Daniel Dudek, a senior economist at EDF and an author of the report. "If we choose the right acid rain control plan, we win the serendipitous benefit of massive reductions in utility carbon dioxide emissions. If we choose the wrong plan, we may actually increase those emissions," he said.

Using data from the Environmental Protection Agency, agency consultants, and industry and other sources, the New York-based environmental group estimated that carbon dioxide emissions by as much as 1.7 billion tons over a decade if the market-based acid rain reduction plan as envisioned in legislation currently on the Senate floor.

"All of the nation's electricity generation facilities would have to be shut down for nearly 10 months in order to achieve similar offsets," said Alice LeBlanc, also an economist with EDF. "The reductions are equal to the amount of carbon dioxide produced in a decade by 22 million cars. Clearly, the market-based plan achieves significant results," she said.

According to the report, the reduction in carbon dioxide emissions under a market-based acid rain control program would be the result of increased investments in energy efficiency improvements, cogeneration and fuel switching. In contrast, alternative control plans that mandate scrubbing, also being considered by Congress, could increase carbon dioxide emissions by as much as 125 million tons, primarily because extra energy is required to operate scrubbers.

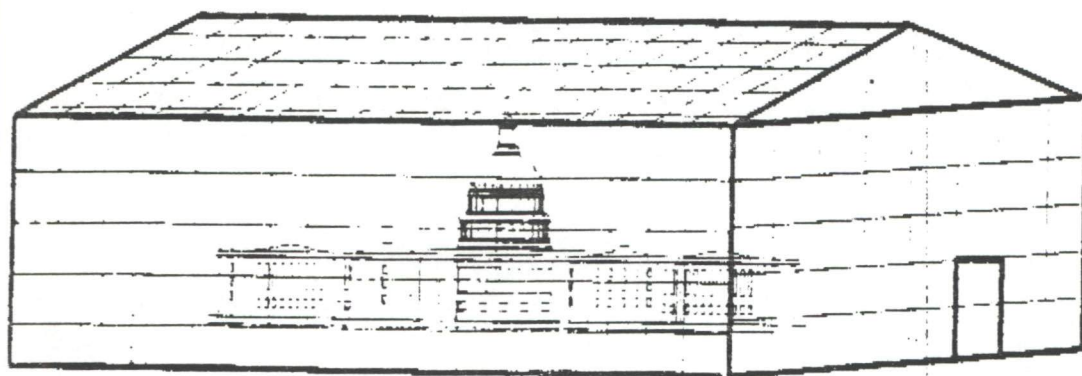
"If we are going to spend valuable resources controlling acid rain, why not increase the benefits of those expenditures by maximizing the opportunities to reduce carbon dioxide emissions as well," Dudek said.

In addition, the report says mandated control technologies would actually stifle investments in conservation and fuel switching, both of which help reduce carbon dioxide emissions. Over time, these constraints would also limit incentives for innovation in pollution control technology because the market for those innovations would be closed by regulators, the report says.

"The Clean Air Act provides policy makers with the opportunity to develop new tools for a new era of pollution reduction. The entire world is looking to the United States for its response to global environmental problems. The Clean Air Act is not only an opportunity to solve the acid rain problem, it is also our first and best chance to lead the world in reducing greenhouse pollution," Dudek said.

Executive Summary

**CO₂ and SO₂:
Consistent Policy Making
in a
Greenhouse**



ENVIRONMENTAL DEFENSE FUND
New York, New York

EXECUTIVE SUMMARY

Overview

This past year has witnessed a resurgence of interest in problems of atmospheric pollution. Two broad scale atmospheric problems have dominated the news: acid rain and global warming. Each has engendered significant national and international policy debate, but they have not been addressed as linked problems. Instead, the constituencies supporting or opposing various policy initiatives have pursued very narrowly focused objectives. This narrowed vision is a primary source of the complex and conflicting mandates of the current Clean Air Act. The current momentum toward reauthorizing the Act should be viewed as a major opportunity for reform which should begin with the recognition of trade-offs among environmental objectives. Chief among these opportunities are SO₂ control strategies which would also reduce CO₂, the primary greenhouse gas.

This report identifies and estimates the CO₂ implications of alternative acid rain control strategies. The primary competing policy opinions under consideration are regulations requiring the use of specific control technologies such as flue gas desulphurization devices versus allowing each source to determine its least cost solution including overcontrol at a smaller number of plants. While each proposal has its CO₂ effects, the market incentives provided by emissions trading would produce a pattern of pollution control investments which maximizes the reduction of CO₂ discharges. If a proposal to regulate only 20 plants in the first phase, coupled with subsidies is adopted, it is doubtful whether either the allowance market or the attendant CO₂ reductions that it would spur would ever materialize. If the options assessed in this report are adopted and if the integrity of the market and its incentives are maintained, we expect a reduction of between 5.4-6.0% in utility CO₂ emissions otherwise expected to occur over the next 15 years. Each of the options analyzed -- interfuel substitution, cogeneration, demand management, and energy efficiency investments -- are economically and environmentally advantageous under emissions trading for acid rain control. The CO₂ reductions are a bonus.

In addition to this bonus, another important linkage exists, for the problems of global warming and acid rain share a key feature. For each, what matters is the total amount of relevant emissions -- CO₂ for global warming, SO₂ and NO_x for acid rain -- released to the atmosphere. Within broad geographic ranges, it makes little difference precisely where the pollutant reductions occur, as long as they do in fact take place.

This feature of both problems offers an opportunity to design strategies that achieve a "bottom line" of a defined overall reduction in pollutants, without requiring all sources to employ similar methods irrespective of their differing technological circumstances. The resulting flexibility can yield major cost savings for achieving a given environmental goal. By implementing this approach for acid rain now, we can demonstrate its viability in time to provide a proven tool for attacking the even more complex problem of global warming.

As the United States enters the decade of the 90's, will policy makers rise to the challenge of developing tools for a new era of pollution reductions or will regional factionalism continue to shackle the future? The rest of the world is looking to the U.S. for its response to global environmental problems. The Clean Air Act is the first best chance to demonstrate the resolve to reduce our share of greenhouse pollution. We do not need to wait for the development of grand international agreements before progress on reducing greenhouse gases can be made. The market based approach to controlling acid rain leads the way.

Major findings:

Using data from the U.S. Environmental Protection Agency, its contractors, the American Gas Association, and other sources, we estimate that enactment of an unconstrained emissions trading program for acid rain would cause utilities to emit 1.5 to 1.7 billion tons less CO₂ than they would otherwise discharge between 1995 and 2005. The cumulative reductions that would result from these anticipated changes in utility behavior are estimated to be as follows:

	(million tons)
Switching from residual fuel oil to natural gas.....	411 - 459
Increased use of cogeneration	424
Decreased use of electricity by consumers in response to minor rate increases	129
Conservation investments by utilities	729
Total projected decreases	1693 - 1741

At the same time, enactment of an emissions trading program would also prompt some individual utilities (or plants) to behave in ways that increase emissions, i.e., by adding scrubbers at some units and/or by burning certain types of low-sulphur coal that has lower energy content (sub-Bituminous coals). These increases are estimated to produce the following cumulative increase in utility CO₂ between 1995-2005:

	(million tons)
Added scrubbing	31 - 125
Sub-Bituminous coal use	10 - 19
Total projected increases	41 - 144

Combining the projected CO₂ decreases and increases provides a net total of CO₂ emission decreases for the decade between 1995 - 2005:

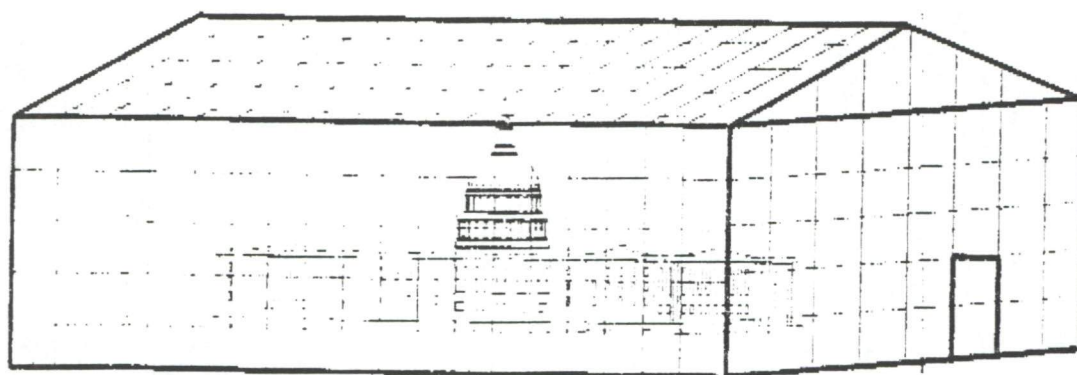
	(million tons)
Projected decreases	1693 - 1741
Projected increases	41 - 144
NET TOTAL DECREASES	1549 - 1700

This total represents a net CO₂ savings of 5.4% to 6% of all CO₂ emissions by utilities over that decade.

Conclusion

Regardless of any other changes influencing future emissions, emissions trading for SO₂ and NO_x will preserve the least cost path for CO₂ management. Emissions trading allows the use of whichever current or future pollution control techniques will reduce discharges most efficiently. As with coal switching versus scrubbing, natural gas substitution for residual fuel oil, and energy efficiency measures, there are ample opportunities to reduce both acid rain precursors and CO₂ simultaneously. Because emissions trading involves a market, it is extremely difficult to forecast actual outcomes. The best that can be done is to indicate what could happen. What new technologies, opportunities, or constraints will emerge over the 15 years assessed in this paper is uncertain at best. Whatever changes those years bring, we can be assured that an emissions market will adjust to the maximum benefit of both the economy and the environment.

CO₂ and SO₂: Consistent Policy Making in a Greenhouse



ENVIRONMENTAL DEFENSE FUND
New York, New York

CO₂ and SO₂:
Consistent Policy Making
in a Greenhouse

by

Daniel J. Dudek,
Alice M. LeBlanc,
and
Peter Miller

ENVIRONMENTAL DEFENSE FUND
New York, New York

January 1990

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1 OVERVIEW

This past year has witnessed a resurgence of interest in problems of atmospheric pollution. Two broad scale atmospheric problems have dominated the news: acid rain and global warming. Each has engendered significant national and international policy debate, but they have not been addressed as linked problems. Instead, the constituencies supporting or opposing various policy initiatives have pursued very narrowly focused objectives. This narrowed vision is a primary source of the complex and conflicting mandates of the current Clean Air Act. The current momentum toward reauthorizing the Act should be viewed as a major opportunity for reform which should begin with the recognition of trade-offs among environmental objectives. Chief among these opportunities are SO₂ control strategies which would also reduce CO₂, the primary greenhouse gas.

This report identifies and estimates the CO₂ implications of alternative acid rain control strategies. The primary competing policy options under consideration are regulations requiring the use of specific control technologies such as flue gas desulphurization devices versus allowing each source to determine its least cost solution including overcontrol at a smaller number of plants. While each proposal has its CO₂ effects, the market incentives provided by emissions trading would produce a pattern of pollution control investments which maximizes the reduction of CO₂ discharges. If a proposal to regulate only 20 plants in the first phase, coupled with subsidies is adopted, it is doubtful whether either the allowance market or the attendant CO₂ reductions that it would spur would ever materialize. If the options assessed in this report are adopted and if the integrity of the market and its incentives are maintained, we expect a reduction of between 5.4-6.0% in utility CO₂ emissions otherwise expected to occur over the next 15 years. Each of the options analyzed--interfuel substitution, cogeneration, demand management, and energy efficiency investments--are economically and environmentally advantageous under emissions trading for acid rain control. The CO₂ reductions are a bonus.

In addition to this bonus, another important linkage exists, for the problems of global warming and acid rain share a key feature. For each, what matters is the total amount of relevant emissions--CO₂ for global warming, SO₂ and NO_x for acid rain--released to the atmosphere. Within broad geographic ranges, it makes little difference precisely where the pollutant reductions occur, as long as they do in fact take place.

This feature of both problems offers an opportunity to design strategies that achieve a "bottom line" of a defined overall reduction in pollutants, without requiring all sources to employ similar methods irrespective of their differing technological circumstances. The resulting flexibility can yield major cost savings for achieving a given environmental goal. By implementing this approach for acid rain now, we can demonstrate its viability in time to provide a proven tool for attacking the even more complex problem of global warming.

As the United States enters the decade of the 90's, will policy makers rise to the challenge of developing tools for a new era of pollution reductions or will regional factionalism continue to shackle the future? The rest of the world is looking to the U.S. for its response to global environmental problems. The Clean Air Act is the first best chance to demonstrate the resolve to reduce our share of greenhouse pollution. We do not need to wait for the development of grand international agreements before progress on reducing greenhouse gases can be made. The market based approach to controlling acid rain leads the way.

2 INTRODUCTION ¹

In the absence of a comprehensive U.S. approach, energy policy is actually made by the Environmental Protection Agency under its mandates from the Clean Air Act (CAA). Because the emission of many atmospheric pollutants are the result of energy production decisions, the regulation of sulphur dioxide (SO₂), nitrogen oxides (NO_x), particulates, etc. directly affects those decisions. In the simplest terms, controlling these pollutants changes the relative costs between alternative energy sources increasing the cost of those that produce larger discharges. These differential environmental control costs alter energy purchase and investment patterns changing both quantities of energy consumed and the method of production. Consequently, environmental policy influences energy production and use decisions more than any other factor except relative fuel prices as determined by market forces.

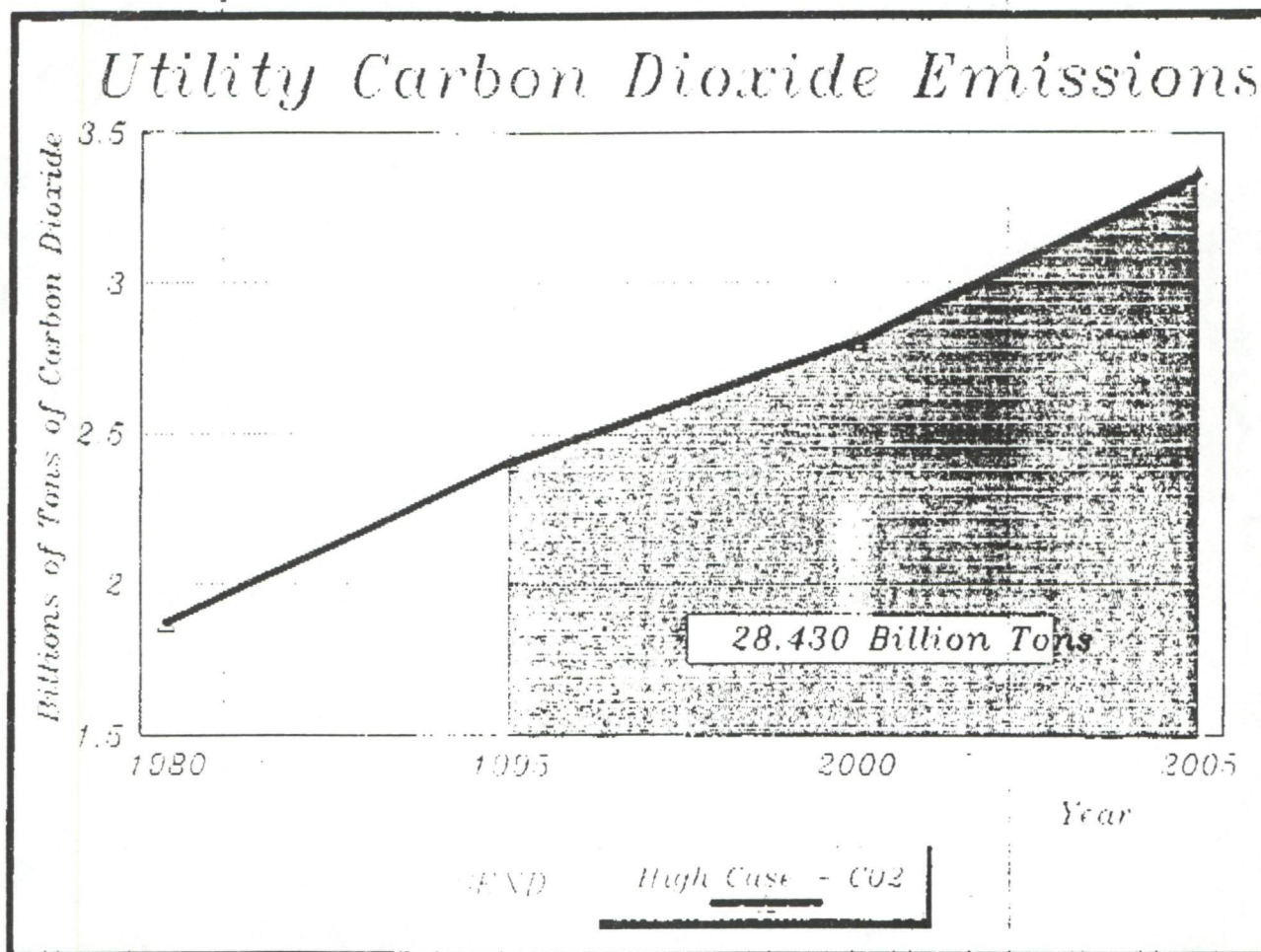
The last twenty years has witnessed a continual evolution of the CAA both in terms of the pollutants that it controls and in the policies used to effect that control. In general, however, management has proceeded on a pollutant by pollutant basis without regard for any cross pollutant effects. Ignoring these cross effects can have serious consequences for both the cost and performance of any environmental policy. This short paper will attempt to explore one particular set of pollutant trade-offs.

In the current debate over reauthorization of the CAA, one of the most hotly contested titles deals with acid rain. The Bush Administration has proposed an innovative emissions trading program to reduce SO₂ and NO_x, the precursors of acid deposition.² Many previous proposals relied upon the use of mandated controls such as flue gas desulphurization (FGD) to achieve reductions. The Bush proposal would allow affected sources to achieve reductions in any manner they chose including investment in over-control at other locations. Plants that can achieve reductions at lower cost are encouraged to produce excess reductions for transfer or sale to plants with higher reduction costs. Since the objective is to reduce emissions discharge as expeditiously and inexpensively as possible, it is critical to take advantage of the cost differences among plants and utilities to achieve these aims. Requiring one specific control technology, e.g. scrubbers, would obliterate the cost savings inherent in these plant differences. The current debate in Congress swirls around these two alternative methods of achieving reductions.

Since both of these policy alternatives would affect operations at the nation's fossil fuel fired electric generating stations, the relevant cross pollutant of concern is carbon dioxide (CO₂) emissions. As hotly debated as the acid rain policy is the issue of U.S. commitment to control the emissions of greenhouse

gases causing global climate changes. On a global basis, CO₂ emissions are thought to account for roughly 50% of the expected warming. In the U.S. which accounts for 23% of global CO₂ contributions, roughly 30% of total CO₂ emissions originate from electric utilities. Figure 1 shows the growth in utility CO₂ emissions under EPA's base case forecast for high SO₂ emissions. This forecast assumes no national acid rain control program and continued low energy prices.

Figure 1. Utility CO₂ Emissions Under the High Base Case



The conventional wisdom is that action to reduce CO₂ emissions or even to damp their growth will be expensive. The main topic explored in this paper is the nature of the relationship between SO₂ and NO_x control on the one hand and CO₂ emissions on the other. Are there serendipitous gains in CO₂ reductions that could be achieved as a result of choosing one policy over another for acid rain control? If we are to expend resources controlling acid deposition precursors, why not increase the benefits of

those expenditures by maximizing the opportunities for CO₂ reductions as well? Many of the options for reducing SO₂ emissions should also produce changes in CO₂ emissions since both gases are the by-products of fossil fuel combustion.

3 REDUCTIONS IN CO₂

Acid rain control expenditures can either increase or decrease CO₂ emissions depending upon the type of policy and the mix of control technologies. The policy choice matters because it may constrain control options available to affected sources. For example, it might limit interfuel substitution which could produce CO₂ savings. Over time these constraints would operate to stifle any incentive for innovation in pollution control technology as markets would have been foreclosed by regulators. Policy also matters because it is a significant determinant of cost which influences electricity demand and therefore atmospheric emissions including CO₂. In fact, this latter effect presents an interesting trade-off. The more expensive the acid rain control program, the greater the impact on utility rates, the greater the electricity demand reduction by customers, and the greater the CO₂ reduction from avoided energy production. However, the more expensive the acid rain program, the less likely it is to be politically feasible due to the more severe impact on the economy. Overall, least cost options tend to be CO₂ reducing. For example, when control technologies are mandated, there is no incentive for conservation by utilities. Not only is the acid rain program more expensive, but any CO₂ reductions are driven solely by electricity consumers' responses. Conservation is not tapped as an emissions reductions tool, even when it is the least cost method.

Since the impacts of SO₂ control have both positive and negative impacts on CO₂, it is important to assess cross-pollutant effects with a systematic accounting framework. The remainder of this paper develops this framework.

3.1 Interfuel Substitution

Some of the most direct CO₂ reductions under a flexible, market based acid rain control program could be produced as a consequence of interfuel substitution. Since fossil fuels differ in their carbon content, they differ in the amount of CO₂ produced during their combustion. Table 1 presents average carbon content for the primary fossil fuels and illustrates the potential for CO₂ reduction. For example, substituting 1,000 Btu from coal combustion with a 1,000 Btu from natural gas reduces CO₂ emissions by over 42%. Similarly, the substitution of natural gas for oil would reduce CO₂ production by over 28%.

TABLE 1. Carbon Dioxide Differences Among Fuels

Fuel	Carbon Content (gC/kBtu)	% CO ₂ Reduced	% CO ₂ Reduced
Coal	25.109		
Oil	20.256	19.33	
Natural Gas	14.454	42.44	28.65

SOURCE: Edmonds and Reilly, 1985.

While the calculations presented in Table 2 are straightforward, there is some uncertainty that these would be the exact reductions achieved when viewed from the vantage of creating a net reduction in greenhouse gas emissions. For example, as researchers have attempted to refine our understanding of the sources and sinks for methane (natural gas) attention has been focused on potential losses from pipelines and gas fields. If pipelines and gas fields leak, then using additional natural gas may increase fugitive methane discharges to the atmosphere. Since methane is a more potent greenhouse gas, the benefits of reducing CO₂ from interfuel substitution might be offset. Research into the sources of methane increases in the atmosphere is continuing. Theoretical considerations indicate that naturally occurring leakage from a gas field is lessened once the field is developed and tapped (Gold, 1988). Gas that is stolen or erroneously metered could also be confused with leaks in the distribution system (see section 4.3 for a more complete discussion).

Other factors which might alter the actual change in CO₂ produced as a result of interfuel substitution include any additional transportation of substituted fuels. For example, to the extent that nearby coals are replaced with more distant fuels, any CO₂ produced as a result of added transport should be netted out. In practice, such changes may be very difficult to estimate as any increased transport would occur either by rail or water each with very different CO₂ implications.³

3.1.1 Residual Fuel Oil to Natural Gas

The amount of substitution of natural gas for residual fuel oil was estimated based on the American Gas Association's (AGA) and Gas Research Institute's (GRI) forecasts of fuel prices and the estimated value of SO₂ emissions permits assuming the Administration's proposed acid rain legislation is passed. The difference in the forecast prices of residual fuel oil (resid) and natural gas was used to calculate the cost per ton of SO₂.

reduction achieved by fuel switching*. This price difference was compared to the value of a permit. No consideration was given to the capital costs involved in switching, which should be relatively low, or to the value of NO_x reductions that would also be produced from the substitution. The assumption is that most, if not all, of the resid-fired plants are capable of firing natural gas and that they will have access to gas supplies.

Table 3 presents the results of these calculations. The cost effective SO₂ emissions rate is the emissions rate at which the cost per ton of SO₂ reduced by fuel switching equals the expected market value of a permit. At a SO₂ emissions rate above this rate, the utility can switch from resid to natural gas and achieve reductions at a lower cost than by buying permits. This analysis uses the equilibrium market values predicted by the EPA and ICF in their analysis of the Administration's proposal. This ignores any economic incentive to bank emissions over time. Given this opportunity and the time cost of capital, we would expect the equilibrium values of SO₂ permits to be monotonically increasing over time unless a radically new control technology shifts the supply curve and reduces the marginal cost of control. The total mMBtus of heat generated by resid burning utilities with SO₂ emissions rates above the cost effective rate were derived from the NURF85 data base.⁵ Total mMBtus generated from oil were obtained from the EPA high emissions base case forecast.

If the relative price changes forecast by AGA materialize, then resid will be more expensive than natural gas by 1995. On that basis alone, one would expect natural gas to replace resid. GRI, however, expects gas prices to remain above residual fuel oil prices. Nonetheless, incentives to switch to natural gas are provided under emissions trading. To the extent that excess SO₂ reductions are more valuable than estimated by the EPA analyses of H.R. 3030 (S.1490), cost-effective substitutions of natural gas for resid would be relatively greater not only to meet SO₂ control obligations, but also to produce revenue from allowance sales. Another uncertainty in this analysis is natural gas prices. To the extent that gas substitution becomes aggressively exploited as an emission reduction strategy, natural gas prices could rise as a result of increased demand if supplies do not expand. Natural gas supplies are currently tightest in the Northeast. However, gas storage could overcome capacity restrictions while pipeline capacity is being expanded.

TABLE 3. Substitution of Natural Gas for Residual Fuel Oil

	AGA PRICE FORECASTS			GRI PRICE FORECASTS		
	1995	2000	2005	1995	2000	2005
Total Oil Use (Million mmBtus)	2070	2190	1720	2070	2190	1720
Cost-Effective SO ₂ Emissions Rate (lbs/mmBtu)	0.0	0.0	0.0	0.68	0.026	0.46
Affected mmBtus (above cost effective emissions rate) (Mil- lions)	2070	2190	1720	1556.64	2183.43	1419.00
CO ₂ Reductions (millions of tons/year)	46.58	49.28	38.70	35.02	49.13	31.93

Cumulative CO₂ Reductions 1995-2005 --
411.44 - 459.60
million tons

Regardless of relative prices, provisions of S.1630 support substitution to natural gas by accommodating any emergency interruptions of gas supplies without any emission penalties if resid is used temporarily. Under these provisions (Section 405(h)), owners of plants using primarily natural gas can receive additional allowances from EPA to cover any SO₂ generated from switching to residual fuel oil during emergency weather conditions. By anticipating the potential operating conditions that this class of plants would face, S.1630 encourages natural gas substitution and the resulting CO₂ reductions.

3.1.2 Natural Gas Penetration Against other Fuels

A number of SO₂ control options which use natural gas have been identified. For example, gas reburn alone and gas reburn combined with sorbent injection would achieve about a 9% CO₂ reduction for a 20% natural gas substitution in existing large coal-fired units (AGA, 1989). Most current studies of the relative economics of alternative SO₂ and NO_x control technologies

conclude that natural gas is likely to be too expensive to expect these alternatives to be very widespread (ICF, 1989). Nonetheless, these expectations about natural gas substitution are based upon future relative fuel prices, notoriously difficult quantities to predict. The critical point is that a flexible emissions trading program would not preclude the use of such options if they became economic at a later date.

Another indication of the potential for natural gas substitution is presented in a DOE study of fuel substitution without any new capital investment (DOE, 1989). In that study DOE estimated that roughly 6 billion mmBtu of coal could be replaced with natural gas. If indeed no new capital investments would be required, and if gas supplies were not constraining, this substitution would reduce cumulative CO₂ emissions by 2.44 billion tons in the 1995-2005 period. Clearly, gas supplies and prices would be the critical factors in determining how much of this substitution occurred.

Another longer run possibility for natural gas substitution under the acid rain titles of proposed legislation is offered by the repowering provisions. Converting large coal-fired boilers to 100% natural gas is estimated to reduce CO₂ emissions by 43%. Combined cycle conversion would increase this reduction to 64% (AGA, 1989).

3.2 Cogeneration

There are two types of CO₂ reductions that result from the replacement of standard electric utility generation by cogeneration. The first is a result of fuel switching if the fuel used by the electric utility has a higher CO₂ emissions rate than the fuel used by the cogenerator. The second type of reduction is the result of greater efficiency in the cogeneration unit in the production of both electricity and steam.

Estimates of new cogenerated and small power electricity were obtained from a report entitled "Background Documentation for 1989 Base Case Forecasts, Final Report" prepared for the EPA by RCG/Hagler Bailly. The difference between the new cogenerated electric power forecasts in the high and low emissions scenarios was taken as an estimate of additional cogeneration that would occur along with the Administration's proposed acid rain legislation. Because the legislation would cause electricity rates to increase and would require SO₂ emissions permits to be obtained for new electric utility capacity, it would stimulate development of new cogeneration capacity by industrial users who face higher rates and would strengthen a preference in utilities to buy new capacity from outside.⁶

The differences in forecasted electricity obtained from new cogenerated sources in the two scenarios were multiplied by 90% on the assumption that 10% of these estimates represent new small power sources that are not cogeneration units. The results of this calculation are the numbers listed as "new kwh cogenerated" in Table 5.⁷

Total CO₂ reductions from cogeneration are calculated by first adding the CO₂ emissions from the production of electricity in coal fired electric utility power plants and the CO₂ emissions from industrial processes using regular industrial boilers to obtain total CO₂ emissions from the energy production that the cogenerated energy is replacing. Subtracting the total CO₂ emissions of the cogeneration facilities produces the estimate of CO₂ reductions attributable to cogeneration.

TABLE 4. CO₂ Reductions due to Cogeneration^a

	1995	2000	2005
New KWH Cogenerated (billions)	18.0	74.7	114.3
CO ₂ Generated by Electric Utilities from Coal, displaced by Cogeneration (million tons)	18.18	75.45	115.44
CO ₂ Generated from Industrial Processes, displaced by Cogeneration (million tons)	21.78	136.01	208.11
Total CO ₂ Displaced by Cogeneration (million tons)	39.96	211.46	323.55
CO ₂ Generated by Cogeneration from Coal and Gas (million tons)	27.68	166.90	255.37
Annual Net CO ₂ Reduction Attributable to Cogeneration (million tons)	12.28	44.56	68.18

Cumulative CO₂ Reduction 1995-2005 -- 423.92 million tons

The offset requirement for new SO₂ sources would increase the relative costs of coal-fired cogenerating plants. Coal-fired capacity is expected to be 30% of expected increases in 1995 and

50% thereafter. After 2000 when offsets would have to be secured to maintain the national SO₂ cap, allowances are expected to cost between \$650-\$771 per ton. Independent power producers possess a number of significant cost advantages which should allow them to easily absorb these added costs. Of course, some concern has been expressed that independent power producers (IPPs) would be shut out of the market by anti-competitive behavior on the part of utilities, the main allowance holders. To combat these perceived problems, several policy modifications have been either proposed or introduced. S.1630 would withhold 2% of the allowance allocation in an Administrator's reserve which would be sold to sources unable to purchase allowances in the market at a fixed price of \$1500 per ton. An alternative which has received wide discussion is to auction annually 5% of allowance allocations. This alternative would also serve a price discovery function and reduce uncertainties about allowance values. In any event, the offset provisions will not pose a barrier to the continued penetration of cogeneration.

3.3 Electricity Demand Response

One of the most easily quantified CO₂ reductions would stem from the reduction in electricity demanded as utility rates rise in response to SO₂ control costs. The strength of this response depends both upon the cost of the control program (and therefore the size of the rate hikes) and the responsiveness of demand (the price elasticity of demand). Another issue in the estimation of this effect is any time lag between the rate hikes and demand response.

Estimates of the long run price elasticity of demand are at best uncertain. A fairly recent survey of elasticity analyses (Bohi and Zimmerman, 1984) published a "consensus" estimate for the residential demand sector, but found that estimates for the industrial and commercial sectors were too few and varied to permit identification of a similar "consensus" estimate. For example, while the survey found 20 studies that estimated the price elasticity of demand for the residential sector, there were only 2 for the commercial sector, and 6 for the industrial sector. The "consensus" estimate for the residential sector was -0.7, i.e. a 1% price increase would produce a 0.7% reduction in the quantity demanded. The estimates for the "commercial" sector ranged from -1.05 to -4.56 while estimates for the industrial sector ranged from -0.12 to -3.55. Despite the uncertainty regarding elasticity estimates for the commercial and industrial sectors, the consensus opinion is that they are more elastic than those for residential demand. In part, the uncertainty in price elasticities is compounded by the need to produce an estimate for the nation as a whole as responsiveness also varies across

regions as well as sectors. The long run elasticity used in Table 5 was -0.85 in part to account for greater responsiveness in the commercial and industrial sectors.

The potential for lags in response time also complicate the analysis. Electricity consumption decisions are conditioned, in part, by the efficiency of various capital equipment whether appliances or machinery. In the short run, consumers may have very limited options in response to price increases. This is not to say that they are nonexistent as simply devoting more attention to use decisions and patterns can reduce consumption. However, over the long run, adjustments can also include investment in complementary goods such as more energy efficient appliances.

Table 5 shows the effect of forecast electricity rate increases on demand for electricity and on CO₂ emissions resulting from electricity generation. Price increases were taken from ICF's analysis of the Administration's proposed acid rain legislation. Rate hikes from that report were adjusted upward to reflect the percent change in real terms from rates in 1988. The short-run elasticity of demand for electricity of -0.25 was used to estimate the demand response in order to avoid double-counting with the conservation investment analysis which follows. It was also assumed that the reduction in electricity consumption displaced electricity generated at coal burning facilities. To the extent that reduced demand displaces natural gas fired peaking units first, these estimates are biased upwards by the difference in CO₂ between coal and natural gas.

Although the Wise Bill (H.R. 3211) is substantially more expensive than S.1630 at \$3.0 billion in 1995 and \$5.8 billion in 2000 due to the emphasis on control technology and subsidies, electricity rate hikes are comparable. ICF forecasted national average utility rate increases of 1.8% in 1995 and 1.7% in 2000. CO₂ reductions are consequently slightly lower although comparable on the basis of demand response (see Section 4.1 for other CO₂ implications).

TABLE 5. Effect of Higher Electricity Prices

	Short Run Elasticity			Long Run Elasticity		
	1995	2000	2005	1995	2000	2005
% Price Increase	0.23	1.70	1.95	0.23	1.70	1.95
Electricity Demand (billions kwh)	3080.7	3524.0	3957.6	3080.7	3524.0	3957.6
Demand Change (billions kwh)	-1.771	-14.977	-19.293	-6.023	-50.922	-65.597
Demand Change (billion mmbtu)	-0.018	-0.150	-0.193	-0.060	-0.509	-0.656
CO ₂ Change (million tons/year)	-1.79	-15.13	-19.49	-6.08	-51.43	-66.25

Cumulative CO₂ Reductions 1995-2005 --
128.85 - 438.00 Million Tons

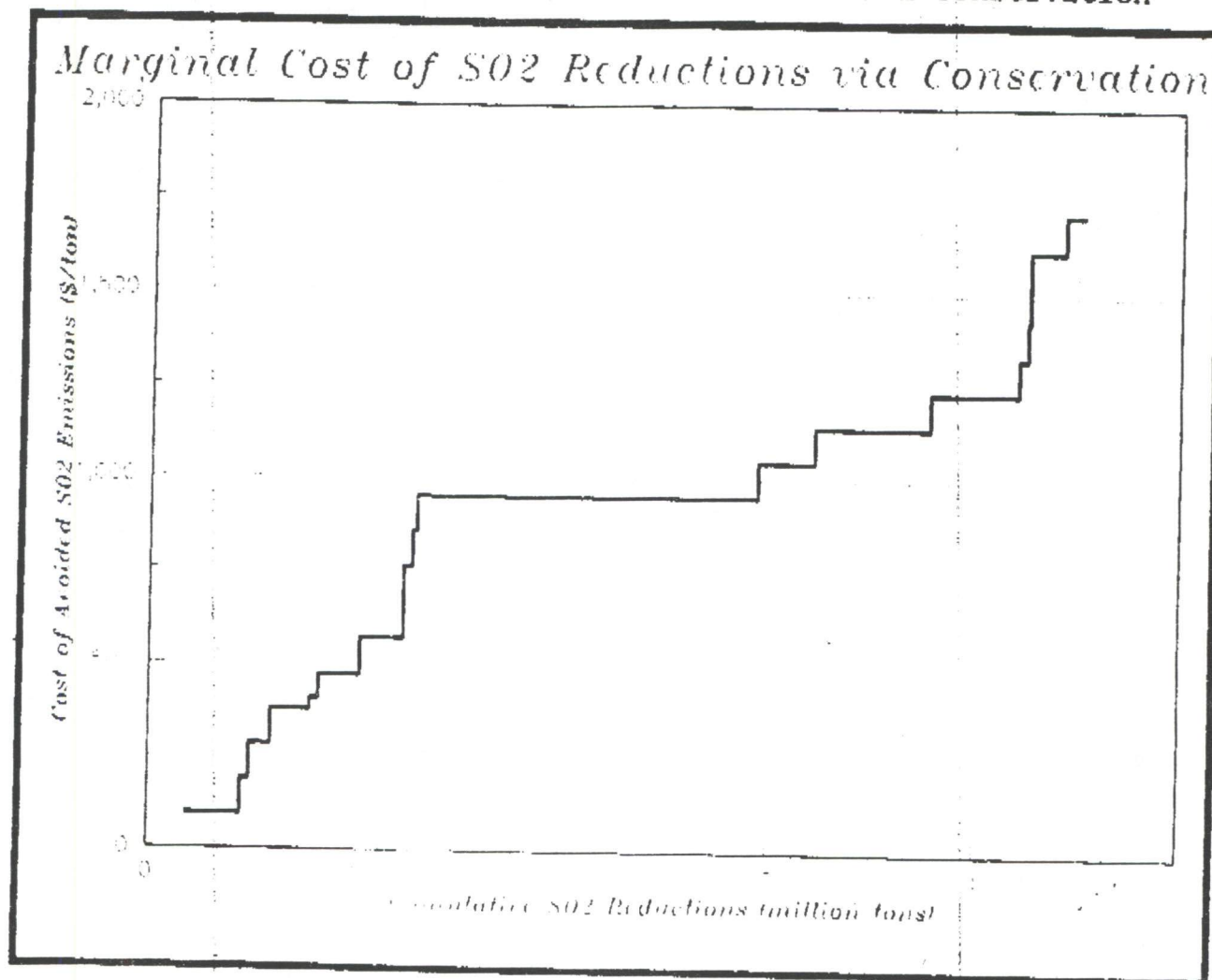
3.4 Energy Conservation Investments

The Administration's proposed acid rain legislation will allow utilities to invest in conservation programs as a cost effective SO₂ emissions control measure. To the extent the programs are successful, they will result in reduced CO₂ emissions as well. Examples of cost-effective conservation measures include increasing the efficiency of residential appliances such as refrigerators and freezers, removing excess fluorescent lighting and reducing air flow rates in commercial spaces, and installing more efficient lighting and motors in the industrial sector.

In order to estimate the amount of conservation that can be induced as cost effective SO₂ emissions control, two cost curves were developed to determine feasible conservation levels. The first is the marginal cost per ton of SO₂ emissions reductions under the Administration's proposal plotted against total amount of reduction below 1980 levels.⁹ As would be expected, marginal cost increases as more tons of SO₂ emissions are eliminated.

The second curve represents the marginal cost of conservation measures per ton of SO₂ emissions reductions plotted against total amount of reductions below 1980 levels. This curve was derived as a weighted average of regional conservation cost curves from New York state, the Pacific Northwest, and the Midwest from a set of engineering-economic analyses. Each of these curves represents the maximum kwh saved for a given level of investment per kwh.¹⁰ These curves were translated into total tons of SO₂ reduced and dollars per ton of SO₂ reduced using the assumption of a 2.0 pounds per mmBtu SO₂ emissions rate and a standard electric utility heat rate of 10,000 Btus/kwh. A 2.0 lb/mmBtu SO₂ emissions rate is the average emissions rate for all coal to be burned under the proposed legislation, as estimated by ICF.

Figure 2. The Supply of SO₂ Reductions from Conservation



There are two conditions which must be met for these conservation benefits to be realized. The first is the adoption of the emissions trading program for acid rain. Without a system which credits conservation investments with the reductions they produce, conservation remains an opportunity without motivation or incentive. The second condition is the removal of any remaining institutional barriers against conservation investments. This latter condition is more difficult to evaluate. However, one potential remedy may be to increase the incentives created by the Clean Air Act.

One possibility for the creation of new incentives would be to create a pool of bonus allowances which would be available to sources within states that adopted programs designed to encourage conservation investments. Examples of such programs include least cost planning, incentive rate of return, and energy supply bidding. One potential source of the bonus allowances could be the allocations made to the clean plants under S.1630. Under that proposal, each clean plant would receive allowances equal to 120% of its baseline (defined as its average 1985-87 fuel use) times the lesser of its allowable 1985 emissions rate or its actual 1985 emissions rate. Alternatively, 20% of those allowances could be held back to form the bonus pool. As Figure 3 shows such a program would involve nearly every state and thus would not be inherently unfair in redistributing allowances. This bonus pool would serve as a powerful additional incentives to the adoption of programs which would further encourage conservation investments.

Other measures to increase the incentives for energy efficiency investments could be introduced into the CAA. For example, the revenues generated by S.1630's 2% allowance withholding could have redistribution limited to sources in those states in which conservation programs exist. This same stricture could be applied to revenues from any auction of allowances as well. These added incentives could insure that the substantial emissions reductions available through energy efficiency investments are tapped in fact.

The two curves were then compared for each of the three years (1995, 2000 and 2005) to find the point at which the following two conditions hold: 1. the marginal cost of conservation measures per ton SO₂ reduced equals the marginal cost of other SO₂ control measures -- i.e. the marginal costs on the two curves are equal and 2. total tons SO₂ reduced from both curves equals the mandated level of SO₂ reductions. This result is equivalent to determining the level at which the conservation programs are cost effective SO₂ control measures.

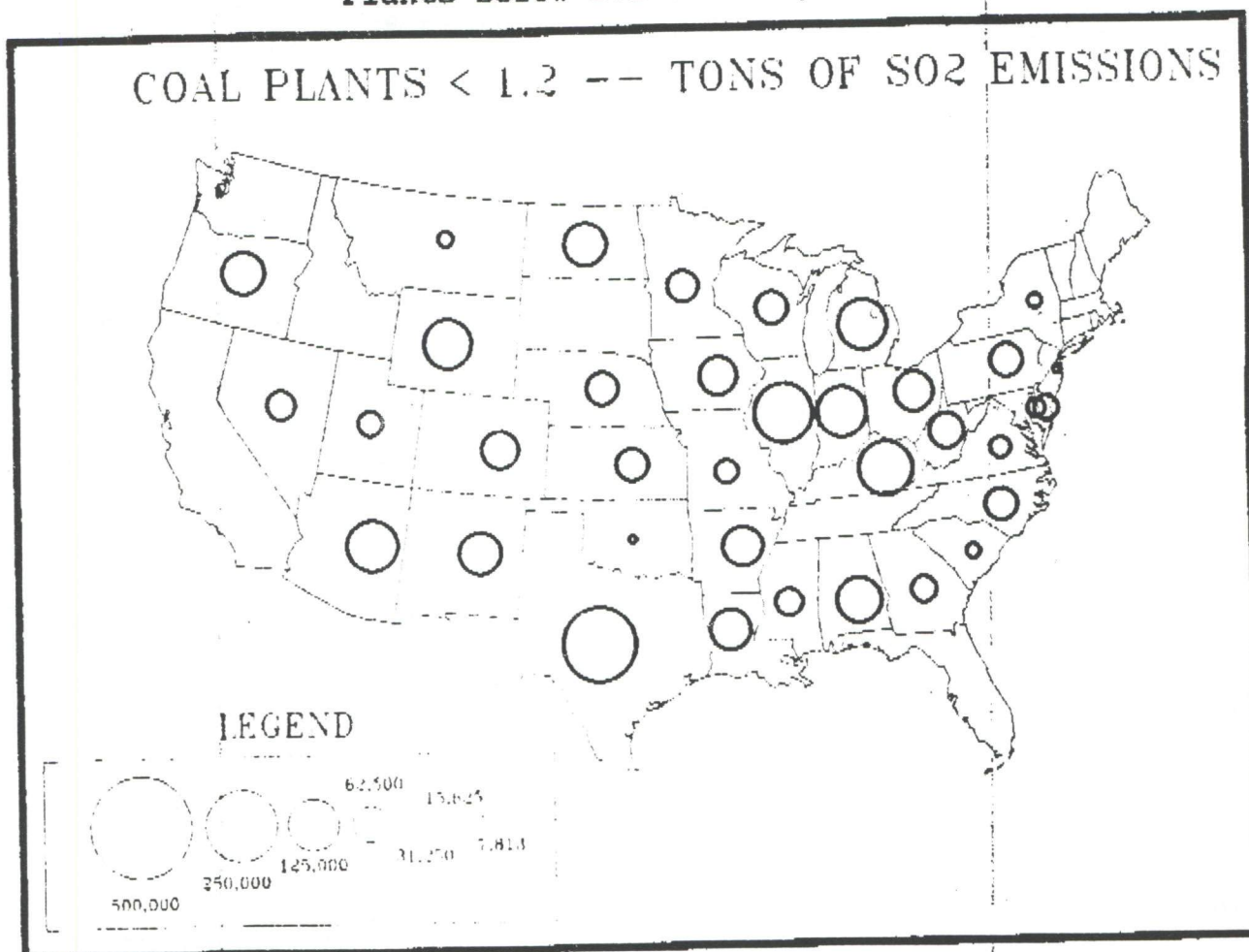
Once this level was determined, the CO₂ reductions for the kwh saved by conservation were calculated using the standard CO₂ emissions rate for coal and the standard heat rate for the electric utility. It was assumed that the conservation measures displace the use of coal, the dominant fuel consumed by the nation's electric utilities. To the extent that more expensive sources of electricity such as natural gas peaking units are eliminated through conservation first, this analysis overstates the SO₂ and CO₂ reductions.

TABLE 6. Effect of Conservation Investments in Reducing CO₂

	1995	2000	2005	2010
Marginal Cost of SO ₂ Emission Reductions (\$/ton)	\$120	\$500	\$500	\$500
Potential Electricity Savings from Conservation (GWh/year)	32,214	86,283	96,672	108,313
Potential SO ₂ Emissions Reductions from Conservation (million tons)	0.35	0.91	1.02	1.15
Potential CO ₂ Emissions Reduced from Conservation (million tons)	32.54	87.15	97.64	109.40

Cumulative CO₂ Reductions 1995-2005 -- 728.62 MILLION TONS

Figure 3. Regional Distribution of Emissions from Coal-Fired Plants Below 1.2 lbs SO₂/mmBtu



4 INCREASES IN CO₂

In order to properly estimate the effect of alternative acid rain control policies upon greenhouse gas emissions, any potential source of emission increases must also be assessed. Certainly, relative to no control scenarios, investments to control acid rain precursors will affect CO₂ emissions as energy production and use decisions are altered.

4.1 Scrubbing SO₂

The use of flue gas desulphurization, or scrubbing, as a SO₂ emissions control measure increases CO₂ emissions primarily because extra energy is required to operate the scrubbers. The extra energy is obtained from additional coal burning which results in higher levels of CO₂ emissions for the same amount of electricity generation. In addition, some CO₂ is produced in the reaction of the limestone agent with SO₂. The range of the total

increase in CO₂ emissions attributable to scrubbing is from 2% to 6%, with a probable average of 4%. (Source Memo from Bruce Braine, ICF to Rob Brenner, EPA December 1988.)

Assuming a 4% increase in CO₂ emissions as a result of scrubbing, the following table shows the extent of additional CO₂ emissions under the Administration's proposed acid rain legislation. Estimates of new scrubbing capacity come from the "Economic Analysis of Title V of the Administration's proposed Clean Air Act" prepared by ICF for the EPA. The total increase in CO₂ over the period from 1995 to 2005 represents about one tenth of one percent of the total CO₂ emissions from electric utilities forecast in that time period under the high emissions base case.

TABLE 7. Effect of New Scrubber Capacity on CO₂ Emissions under the Administration's Proposal

	1995	2000	2005
Change in Scrubber Capacity (GW)	.5	22.0	22.0
Total New Gwh Scrubbed	2,269	99,829	99,829
Increase in CO ₂ Emissions (Million tons)	.09	4.03	4.03

Cumulative CO₂ Increase 1995-2005 -- 30.48 Million tons

In contrast to the estimates presented above, more new scrubbing capacity would come on line as a result of alternative legislation, such as the Wise Bill, that mandates the use of scrubbers as a SO₂ control measure. An examination of the effects of the Wise Bill during the period 1995 to 2005 indicates an addition of almost 125 million tons of CO₂ emissions resulting from increased scrubbing (ICF, 1989). The freedom of choice in SO₂ control strategy allowed under emissions trading would clearly lead to fewer additions to CO₂ emissions from new scrubbing capacity.

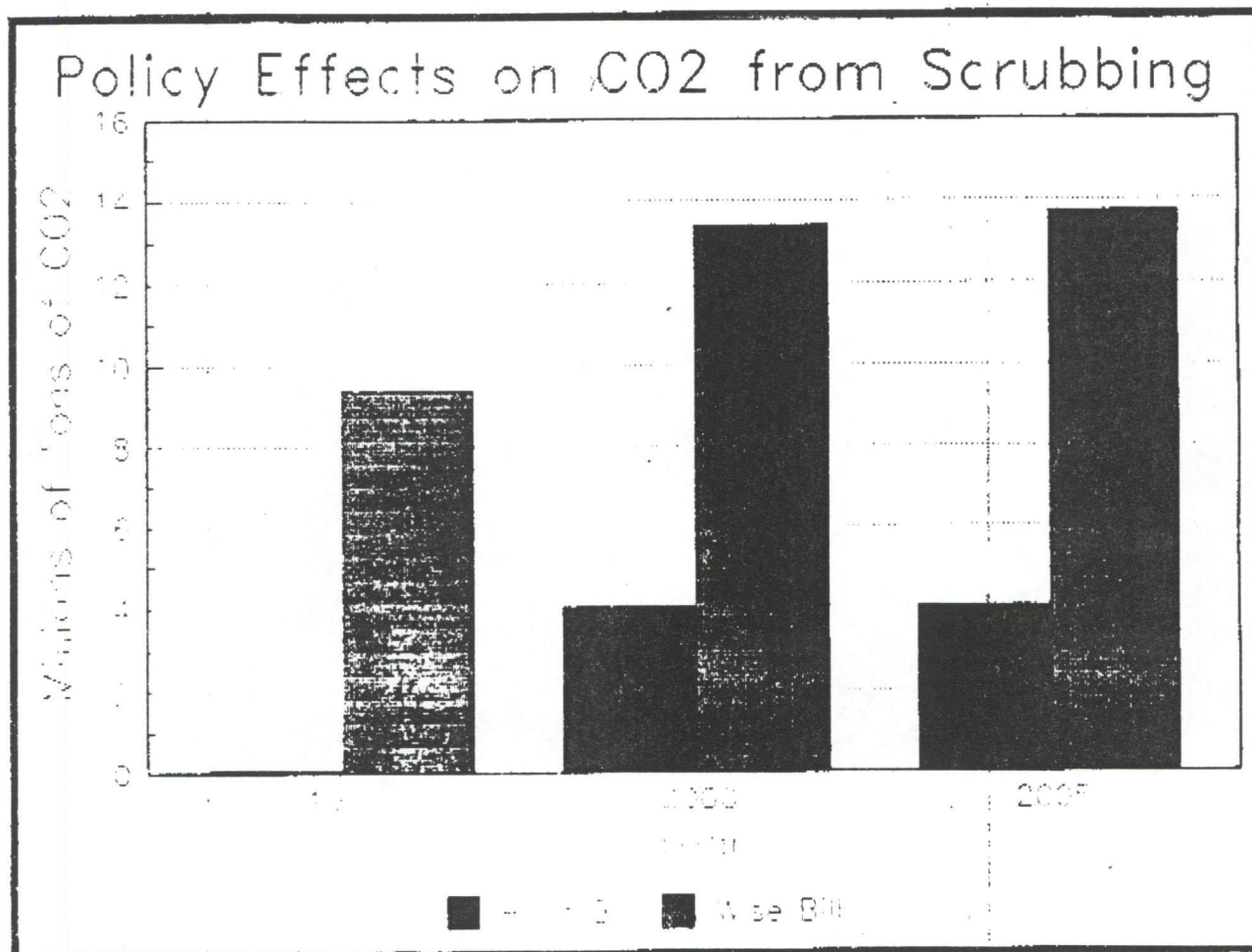
TABLE 8. Effect of Scrubbing on CO₂ Emissions Wise Bill

	1995	2000	2005
Change in Scrubber Capacity (GW)	51.2	73.0	74.9
Total new Gwh Scrubbed	232,319	331,251	339,872
Increase in CO ₂ Emissions (Million tons)	9.39	13.38	13.73

Cumulative CO₂ Increase 1995-2005 -- 124.7 Million Tons

The Wise Bill (H.R. 3211) would require the top 20 SO₂ emitting powerplants in 1985 to reduce SO₂ emissions by 90% through the use of flue gas desulfurization devices. These Phase I reduction requirements would be augmented by a second phase during which all sources above 75 megawatts capacity would have to meet a 1.2 lb SO₂/mmBtu requirement. In each phase, subsidies would be provided to utilities employing scrubbers to meet their control obligations. As Figure 4 illustrates, these provisions would lead to a dramatic increase in scrubbing and CO₂. Furthermore, the actual increase in CO₂ is likely understated since the Wise Bill provisions would probably prevent the emergence of an allowance market. Other proposals that target 20 plants in Phase one and legislate a subsidy are under discussion in the Senate. They are likely to produce a CO₂ result similar to the Wise Bill.

Figure 4. CO₂ from Scrubbing Under Alternative Acid Rain Proposals



4.2 Switching to Fuels with Lower Energy Content

With the enactment of acid rain legislation that allows flexibility in choice of control methods, it is expected that some utilities will switch to the use of coal with a lower sulphur content. Some of the switching will occur between high sulphur and low sulphur bituminous coals from Appalachia. This substitution will have little effect on CO₂ emissions as there is little variation among bituminous coals. However, some Mid- Western utilities will switch from high sulphur bituminous coal mined in Appalachia to low sulphur sub-bituminous coal from more distant Western areas. Because sub-bituminous coal has on average a higher moisture content than bituminous coal, it can cause a utility's heat rate to rise and result in more coal burned per unit of electricity generated. The estimated increase in CO₂ emissions resulting from a switch from bituminous to sub-bituminous coal is 2%.

ICF's analysis of acid rain control technologies assumes that no sub-bituminous coal can be used in boilers designed for bituminous coal, although their assessment of the Administration's acid rain proposal notes that 40 to 50 million tons per year of sub-bituminous coal could penetrate the bituminous market. Data Resources Inc. (DRI), on the other hand, estimates that 29 million tons a year in Phase 1 and 25 million tons per year in Phase 2 will represent a switch from high sulphur bituminous coal to low sulphur sub-bituminous coal. Based on these forecasts Table 9 displays estimates of additional CO₂ emissions. The high end of the range of cumulative CO₂ increases assumes the high end of ICF's estimates of sub-bituminous market penetration for this entire decade.

TABLE 9. Effect of Coal Switching on CO₂ Emissions

	DRI FORECAST 11			ICF FORECAST
	1995	2000	2005	2005
Switch to Sub-bituminous Coal (Million tons)	29	25	25	40-50
Efficiency Loss (Million tons of Coal)	0.58	0.50	0.50	0.8-1.0
Increase in CO ₂ Emissions (Million tons)	1.12	0.96	0.96	1.54-1.92

Cumulative CO₂ Increase 1995-2005 --
10.01 - 19.20 Million Tons

4.3 Potential Effects on Other Greenhouse Gas Emissions

Leakage of methane (natural gas) in the production, transmission and distribution processes is an issue that should be addressed because methane is a far more potent greenhouse gas than CO₂. Leakage occurs naturally in gas fields as a result of pressure exerted by the gas. Production, by removing some of the gas, reduces the pressure and the naturally occurring leakage. However, production equipment is another source of leakage. Unfortunately, little research has been conducted to measure the overall effect of production on leakage.

Leakage also occurs in the transmission of gas through pipelines and its distribution in individual customer grids. The magnitude of this leakage appears to be related to the age and material composition of the transmission and distribution systems. While the leakage is difficult to measure, it is clear that the amount of "unaccounted for" gas in the United States also includes theft, measurement inaccuracies caused in part by meter sensitivity to temperature and variations in gas purchase and sale billing dates.

Several studies and surveys have recently been conducted to estimate the extent of methane leakage worldwide and in the U.S. An "Engineering Technical Note" by the American Gas Association dated November 1989 estimates, based on a survey of members, that 0.06% is emitted in transmission and 0.28% in distribution. In

addition, the AGA estimates 0.2% is lost in production. The Interstate Natural Gas Association of the U.S. estimates that transmission pipelines account for emissions of 0.13%.

"Methane Leakage from Natural Gas Operations" reports the results of an investigation by the Alphanatania Group of Sweden in August 1989. The report presents information on gas leakage in the U.S., Canada, Japan and 10 European countries. It concludes that there is no justification for estimating methane leakages from the gas industry worldwide at more than 1% of supply and that even this figure is regarded by many as too high. It also states that there is strong evidence that the only significant methane leakage occurs in older distribution systems found in some countries. Based on the countries surveyed, the following estimates are made for methane leakage: Production 0 to 0.2%; Transmission 0 to 0.13%; New distribution systems 0.03 to 0.3%; and Old distribution systems up to 1%.

The Netherlands Energy Research Foundation presented a study in Paris in June 1989 entitled "CH₄/CO Emissions from Fossil Fuels Global Warming Potential." The study addresses whether fuel switching strategies to mitigate the green house effect would be affected by methane leakages. It concludes that global warming differences in the burning of oil and coal as opposed to gas would be offset by methane leakages if they occurred at the high levels of 9 to 13%.

It is difficult to compare the potency of methane and CO₂ as greenhouse gases because of complexities involved in modeling and forecasting their effective lifetimes in the atmosphere. However, it is possible to compare methane leakage from additional natural gas use brought about by acid rain legislation to coal bed methane leaked in the coal mining process. If we assume that methane leakage from the production, transmission, and distribution of natural gas is 0.5% and that on average 19 cubic meters of methane is leaked per ton of mined coal, the methane leakage from coal mining is approximately 7 times that from natural gas use on an energy equivalent basis. Of course, nothing in this comparison accounts for the fact that emissions from both sources could be controlled.

5 CONCLUSIONS

This report has identified major interrelationships between SO₂ management decisions and CO₂ consequences. Table 10 summarizes the estimates for CO₂ reductions and increases. The cumulative totals indicate that acid rain control provides a serendipitous opportunity to eliminate between 5.4-6.0% of all utility CO₂ emissions over the decade 1995-2005. However, not all acid rain programs are equal in their incentives to simultaneously reduce both SO₂ and CO₂ emissions. Only the market-based

approach embodied in emissions trading will give affected sources the flexibility to choose among the emission control options assessed in this report. Programs which force the adoption of one technology over another, particularly those proposals which would require the use of scrubbers, would forego major CO₂ reduction opportunities and cause increased CO₂ emissions. The major unspoken policy question surrounding the acid rain debate is whether the U.S. should capture these CO₂ benefits. When set against the backdrop of ongoing international discussions concerning climate change policy and the criticism that the U.S. has received on this issue, it is difficult to understand why the relationship between SO₂ and CO₂ has been ignored. The U.S. should strive to adopt an acid rain program that incorporates incentives to reduce SO₂ emissions most efficiently. Further, given increasing concerns about global climate change, that program should be designed to maximize opportunities for CO₂ reductions as well. Is the U.S. so wealthy that we can choose the most expensive approach to solving the acid rain problem, and, at the same time, increase the cost of any ultimate policy action on CO₂?

TABLE 10. The CO₂ Balance Sheet

SOURCE of REDUCTIONS	CUMULATIVE AMOUNT (mm tons)	SOURCE of INCREASES	CUMULATIVE AMOUNT (mm tons)
Resid to Natural Gas	411.440- 459.600	Added Scrubbing	30.480- 124.700
Cogeneration	423.920	Sub-Bituminous Coal	10.010- 19.200
Demand Response	128.850		
Conservation	728.620		
TOTAL	1,692.78- 1,740.99		40.580- 143.900

Cumulative CO₂ Reductions 1995-2005 --
1,548.88 - 1,700.41 Million Tons

Another way to understand the potential magnitude of these CO₂ effects is to compare them with the CO₂ implications of the energy and emission futures that EPA has developed as baselines from which alternative policies can be evaluated (EPA, 1989). The base case analysis produced by EPA this year differs sharply from prior practice in that two alternatives are presented; one

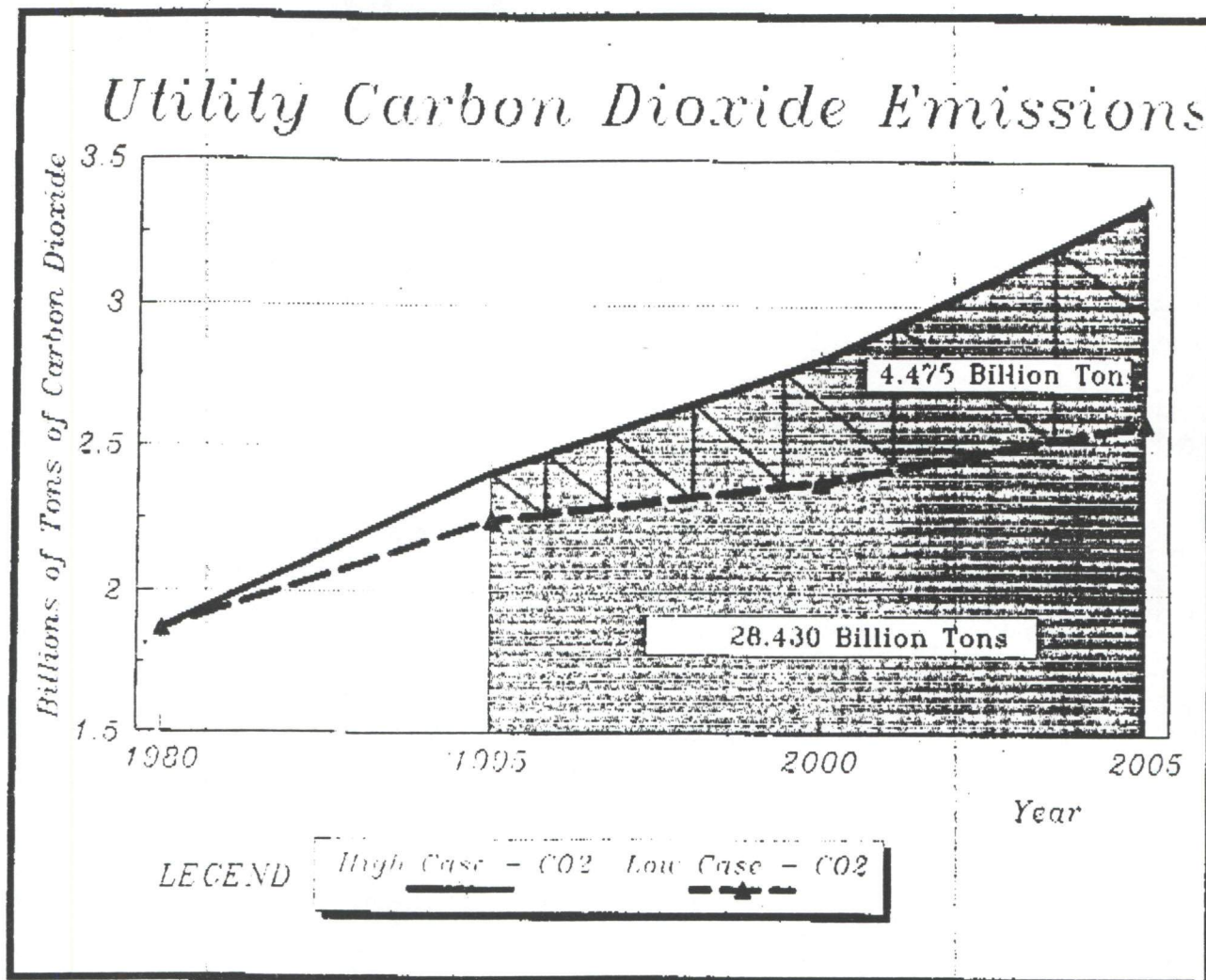
scenario with high SO₂ emissions and an alternative with lower emissions. Table 11 presents the differences in critical assumptions underlying the alternative SO₂ emissions forecasts.

Table 11. Differences Between High and Low Emissions Scenarios

ASSUMPTION	HIGH CASE	LOW CASE
oil and gas prices	lower	higher
electricity demand	higher	lower
repowered capacity	lower	higher
unplanned coal capacity	sooner	later
unplanned non-fossil fuel capacity	lower	higher
cogeneration	lower	higher
fossil fuel plant lifetime	longer	shorter
nuclear power plant lifetime	shorter	longer

Source: ICF Resources, EPA, April, 1989.

The standard approach in analyzing SO₂ policies has been to compare the policy results against alternative future emissions scenarios as depicted in Figure 5. Each of these alternative futures represents the status quo since neither presumes any acid rain control. Unfortunately, there is no way to know which alternative future will materialize. Consequently, as in the case with SO₂, potential CO₂ emission changes should be gauged against both the high and low emissions alternatives. To the extent that the low emissions future occurs independent of any acid rain program, some of CO₂ reduction benefits outlined in this paper would be eliminated. For example, one of the major differences between the high and low tracks in CO₂ terms is the amount of new cogeneration. Both base cases forecast large additions to cogeneration capacity. Will the larger amount of new cogeneration in the low emissions base case occur independent of acid rain legislation? Perhaps, but factors related to that legislation such as higher electricity rates and SO₂ control costs should spur more new investments in independently produced cogenerated power.

Figure 5. ALTERNATIVE FUTURE UTILITY CO₂ EMISSIONS

Source: ICF Memo Report, Analysis of EDF Acid Rain Proposal, May 1989.

Figure 5 presents the high and low SO₂ base case forecasts translated into CO₂ terms. The figure presents CO₂ emissions forecasts only to the year 2005 and concentrates on the decade 1995-2005 when acid rain policies are expected to have the most impact. Cumulative CO₂ emissions from utilities over the decade are expected to be 28.43 billion tons under the high scenario and 23.76 billion tons for the low track. The 4.48 billion ton difference between the two scenarios represents roughly a 16% CO₂ reduction from the high track. Clearly, this is not a trivial

difference. Nonetheless, it begs the question of whether in fact the U.S. economy will actually be on the high or low emissions track.

Throughout this report the potential for CO₂ savings from acid rain legislation has been emphasized. Table 11 presents the key factors presumed to account for the differences in emissions between the high and low scenarios. After investigating a number of CO₂ reduction opportunities and utility reactions under acid rain policies, one can examine the assumptions of Table 11 and inquire which scenario is more likely to occur under emissions trading. Certainly, to the extent that natural gas substitution is encouraged and natural gas supplies do not expand, gas prices will be higher. Electricity prices are likely to rise under any acid rain control program. In response, the quantity of electricity demanded is likely to fall. Cogeneration and unplanned non-fossil fueled capacity are also likely to be greater with any acid rain legislation that emphasizes emissions trading. In sum, the assumptions of the low emissions scenario match closely the expected effects of the administration's acid rain proposal.

Regardless of any other changes influencing future emissions, emissions trading for SO₂ and NO_x will preserve the least cost path for CO₂ management. Emissions trading allows the use of whichever current or future pollution control techniques will reduce discharges most efficiently. As with coal switching versus scrubbing, natural gas substitution for residual fuel oil, and energy efficiency measures, there are ample opportunities to reduce both acid rain precursors and CO₂ simultaneously. Because emissions trading involves a market, it is extremely difficult to forecast actual outcomes. The best that can be done is to indicate what could happen. What new technologies, opportunities, or constraints will emerge over the 15 years assessed in this paper is uncertain at best. Whatever changes those years bring, we can be assured that an emissions market will adjust to the maximum benefit of both the economy and the environment.

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Notes

1 The authors wish to express their appreciation for the financial support of the Joyce Foundation. This paper has benefited from the comments of Karen Florini, Bob Hahn, Dan Kirschner, Elizabeth Nixon, Michael Oppenheimer, Tim Searchinger and Jim Tripp. Others including Michael Gibbs, Thad Huetteman, Bill Liss, John Palmisano, Lori Trayweek, Paul Wilkinson, and Jim Williams have assisted this research by contributing valuable information and suggestions. The contents of this report are the responsibility of the authors however.

2 For a technical analysis of the implications of the Bush Administration's acid rain legislation see ICF Resources (1989). For a more complete discussion of the emissions trading policy see Dudek (1989).

3 A recent report from Shearson Lehman concerning the implications of acid rain legislation for coal markets concludes that barge transport of coal should increase if legislation is passed (Shearson Lehman, p. 37-39).

4 The natural gas prices used in this analysis are for interruptible supplies and represent the prices normally charged to utilities. Both the AGA and the Gas Research Institute (GRI), among others, forecast natural gas and residual fuel oil prices. Their forecasts for interruptible supplies to utilities are shown below in Table 2.

Table 2. Fuel Price Forecasts

Fuel	1995	2000	2010
AGA	1989 \$/mmBtu		
natural gas	\$2.69	\$3.43	\$5.63
resid (No. 6)	\$3.40	\$4.20	\$7.76
GRI	1988 \$/mmBtu		
natural gas	\$3.20	\$3.59	\$5.64
resid (No. 6)	\$3.05	\$3.58	\$5.23

5 The NURF data base identifies the primary fuels used by individual units. To the extent that resid-fired units are already using some natural gas, the estimates of CO₂ savings presented are overstated. The extent of this bias is unknown.

6 The status of cogeneration units under the several acid rain proposals is not unambiguous. Cogenerating units are likely to be subject to the offset requirements for new sources. However, due to the large proportion of cogeneration units that will be gas fired and the greater efficiency of the cogeneration process, offsets required by cogenerators should be substantially less than those required for added utility capacity.

7 Assumptions made to calculate the CO₂ savings include the following. New cogenerated electric power replaces power previously produced from coal fired facilities. In 1995, the new cogeneration sources are 30% coal fired, 47% gas fired combined cycle and 23% gas fired combustion turbine. In 2000 and beyond, the mix is 50% coal fired, and 25% each combined cycle and combustion turbine. Boiler efficiency of industrial boilers is 80%. Efficiency for coal fired cogeneration is 80%, for gas combined cycle is 78% and for combustion turbine is 70%. The average heat rate for a coal fired electric utility is 10,000 Btu/kwh. The ratio of electric to thermal energy (e/t) is 0.13 for coal fired cogeneration facilities; 0.9 for combined cycle and 0.65 for combustion turbine. It was also assumed that new coal fired cogenerated thermal energy would replace energy produced from coal in industrial processes and likewise for natural gas.

8 The CO₂ generated by electric utilities from coal is calculated by converting the kwh in column 1 (new kwh cogenerated) to mmBtus using the average electric utility heat rate and multiplying by the CO₂ emission rate for coal (202 lbs/mmBtu). The CO₂ generated by cogeneration is calculated separately for coal and gas fired cogeneration units and summed in row 3. To do this, an estimate of the fuel input to cogeneration is obtained and translated into CO₂ emissions. For example, for coal fired units, the percent cogeneration that is coal fired according to the assumptions is multiplied by the kwh in row 1 and converted to mmBtus using the conversion 3413 Btus/kwh. An estimate of mmBtus of thermal energy produced is obtained by solving for t in the appropriate equation for coal fired steam turbines, e/t=0.13. The total mmBtus is divided by the efficiency of the cogeneration system, in this case 80% to obtain fuel input which is converted to tons of CO₂ emissions based on the emissions rate for coal. A similar process is carried out for gas fired combined cycle and

combustion turbine cogeneration units. The CO₂ generated by industrial processes is estimated by taking the thermal energy calculated as the value of t above and dividing by the efficiency of the industrial boiler and estimating the level of CO₂ emissions for the appropriate fuel type, coal or gas.

9 The marginal costs of SO₂ control were taken from ICF's analysis of the economic implications of the Administration's acid rain proposal (ICF, 1989). Control measures considered were scrubbing and switching to lower sulphur coal.

10 Each of these curves expresses the relationship between the cost of conservation measures in \$/kwh saved and the total number of kwh saved. The cost of conservation measures consists of conservation program costs and does not account for the cost of lost revenues or the savings from avoided fuel costs. Total kwh saved in the three curves were converted to percent kwh saved. A weighted average was taken to produce a "national" curve. The percentages for kwh saved in the national curve were applied to total projected U.S. electricity use forecast by ICF for the EPA's base case emissions. This procedure was repeated for 1995, 2000 and 2005 to obtain a nationwide conservation cost curve in terms of kwh saved and \$/kwh.

11 DRI believes that most plants would comply with Phase I requirements by blending sub-bituminous coals with other higher sulphur coals. In Phase II, however, DRI believes that utilities will switch to bituminous compliance coals to avoid de-rating plants as required if all sub-bituminous coals were used. Consequently, DRI estimates sub-bituminous coal use to fall over time.