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Cleaner Power: The Benefits and Costs of Moving from Coal Generation to Modern Power Technologies

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Abstract: *This paper analyzes benefits and costs of reducing by half the use of coal for electric generation in the United States by the year 2010, making use of the Haiku electricity market model developed and maintained at Resources for the Future. The analysis indicates that the coal generation would be replaced by generation from modern power technologies such as natural gas turbines, together with a small contribution by wind power and other sources. This transition would address multiple pollution problems, as gas turbines are considerably cleaner and more efficient than the older coal plants they replace. Total pollution levels would fall dramatically, with industry emissions of SO_2 lowered by 50%, NO_x by 40%, mercury by almost 60% and CO_2 by 25% in 2010. The principal economic impact in the electricity sector would be a six-tenths of a cent rise in the price of electricity above a business-as-usual scenario.*

I. Introduction and Summary

The electric power sector faces a number of major initiatives to reduce its emissions of criteria pollutants, air toxics and carbon dioxide. These include:

a) reductions in *nitrogen oxides* in eastern states pursuant to the EPA rulemaking that requires states to attain national ambient standards for ozone;[1]
b) proposed reductions in ambient limits for *particulate matter* and fine particulate matter which seriously impair human health;[2]
c) potential reductions in *sulfur dioxide* required under proposed legislation in Congress, in order to reduce acid deposition as well as particulate formation[3];
d) potential requirements to reduce toxic *mercury* emissions from power plants[4]; and
e) compliance with a *carbon dioxide* emissions cap that has been proposed under legislation dealing with power plants[5], or that could be required under the Climate Change Convention[6].

Since only the NO_x reductions are currently required by law, these initiatives could be addressed by the industry in either a piecemeal or integrated fashion, depending in large part on the implementation and timing of the other regulatory actions. Implementing these policies sequentially could result in a series of incremental additional controls on the older coal-fired power plants that are responsible for all or most of the electricity sector's emissions of each pollutant. In contrast, a transition away from coal towards cleaner power sources could address these multiple policy goals in an integrated fashion, creating a potentially lower cost, pollution prevention solution.

This paper analyzes the consequences of reducing the use of existing coal-fired electric generation in the United States by 25% by the year 2005 and 50% by the year 2010. It makes use of the Haiku electricity market model developed and maintained by Resources for the Future, which is described in Appendix A together with a discussion of how this scenario is constructed and implemented. This analysis shows that total generation would fall only slightly, and that the reduction in exirtin, coal generation would be replaced by generation from natural gas turbines, together with a small contribution from wind power and other sources. Progress in other advanced technologies such as coal gasification and solar power that reduces their economic cost would allow them to also play an increasing role in a clean energy future.

Reducing coal generation under this scenario could address the above pollution initiatives in an integrated fashion, as existing coal-fired plants, mostly built before 1979, produce 60% of national emissions of sulfur dioxide (SO_2), 25% of nitrogen oxides (NO_x),[7] a third of mercury emissions, thirteen other priority air toxics,[8] and 32% of carbon dioxide (CO_2).[9] Modern power technologies such as gas turbines are considerably more efficient and far cleaner than the older coal plants they replace, producing none or very little of the regulated air pollutants emitted by coal-fired plants and about half of the carbon dioxide. Therefore, total pollution levels in the coal reduction scenario fall dramatically, with industry emissions of SO_2 reduced by 50%, NO_x by 40%, mercury by almost 60% and CO_2 by 25% in 2010. Thus, a switch from coal to gas would substantially reduce or resolve many major pollution problems addressed by the Clean Air Act and U.S. international climate change commitments.

Table 1. Percentage of Major Pollutant Reduction Goals Achieved by a 50% Reduction of Coal-Fired Power Generation

Pollutant	Pollutant reduction goal in electricity sector	Percent achieved
NO_x - SIP call	Summer reductions to 500,000 tons in 21 states	70%
SO_2	50% reduction beyond Title IV Acid Rain Program	100%
CO_2	Return to 1990 levels	100%
Mercury	90% reduction from 1990 levels	90%

Two reasons make it especially critical to achieve a shift to modern technologies in the near future. The first is that, in the next few years, power generators are required to reduce NO_x emissions to comply with new regulations, and will be making critical investment decisions on whether to comply by shifting from coal to gas-fired generation, or simply by adding controls to existing older coal plants. Replacing coal-fired generation with modern gas plants would achieve major reductions in five pollutants, not only addressing NO_x emissions but making it far easier to address other major pollution problems.

The second pressing reason is the need to reduce carbon dioxide, a greenhouse gas with a lifetime of hundreds of years, in the near term. Making reductions over the next decade will be critical to stabilizing global carbon levels in the future, and can most immediately and practically be achieved by switching from coal-fired to gas-fired power generation. In the longer term, achieving a further conversion towards renewable and other non-polluting energy technologies is a priority in achieving climate change and other goals.[10]

The reductions in SO_2 and NO_x lead to reductions in secondary pollutants, including fine particulates. Health benefits from particulate reduction alone are estimated at $26.4 billion per year, using the modeling capacity of the Tracking and Analysis Framework to estimate changes in atmospheric concentrations of particulates and their health effects (described in Appendix A). Significant additional benefits also would derive from the lowered pollution levels, including major reductions in ozone levels, acid deposition, mercury contamination and carbon dioxide emissions. In reality, any of these pollutant reductions alone could provide a compelling basis for reducing coal-fired generation.

This report reveals that the shift to modern gas turbines caused by the 50% coal reduction can be expected to raise the price of electricity by six-tenths of a cent per kilowatt hour in 2010. Because gas plants are more efficient, total energy requirements actually decrease in comparison both to a business-as-usual scenario and a 1998 baseline. However, significant additional natural gas supplies are required, which would add 25% to the total gas demand in 2010.[11] The shift from coal to gas-fired generation creates economic costs within the electricity generating sector of $25.9 billion per year, primarily consisting in higher electricity prices to consumers, but also in lower producer profits.[12] Offsetting these costs are the health benefits described above, together with other significant pollutant reductions.

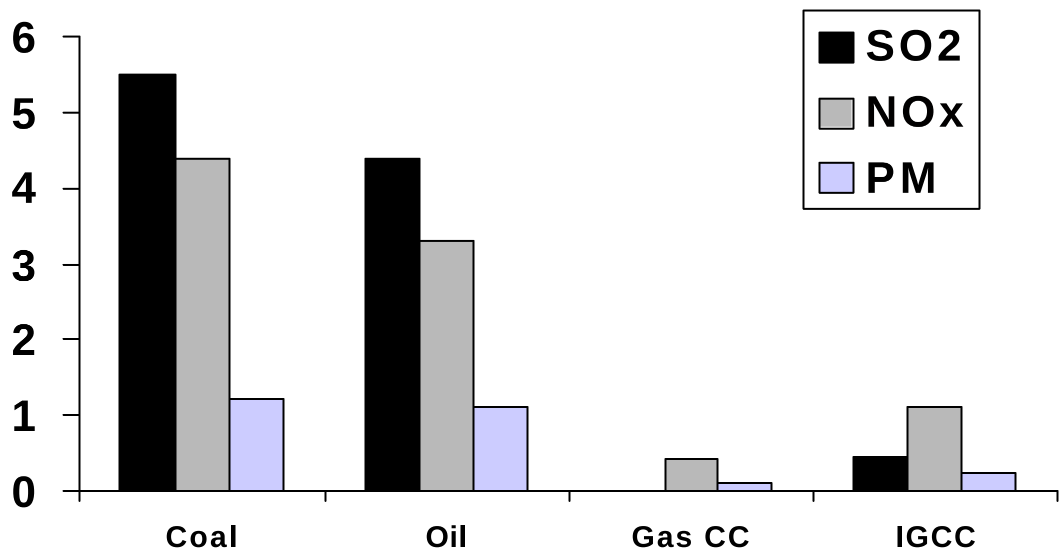
II. Regulatory and Economic Policy Context

Although there are major pollution benefits in switching from existing coal generation to modern power technologies, the economic and regulatory forces currently faced by power companies do not compel the switch. There are three primary barriers to this change: (1) standards for SO_2 and particulates have not yet been lowered, (2) only seasonal reductions of NO_x are being required, (3) and CO_2, mercury, and other hazardous air pollutants are not yet regulated. Therefore, while retiring coal plants and switching to new gas power create major social benefits and may make economic sense in a multi-pollutant context, power companies may be more likely to add specific end-of-stack controls to older coal-fired plants as long as not all air pollutants are regulated, or if air pollutants are only regulated one by one.

Thus, the economic and regulatory context governing the power sector today results in a situation that encourages power plants to continue operating old coal-fired facilities as sources for 50% of U.S. power, rather than converting to natural gas.[13] The model predicts that in the absence of a policy to reduce emissions from these older plants, few existing coal plants will retire or stop generating in the next decade, just as very few have retired over the past decade. The overall business strategy that power companies are likely to adopt, therefore, depends in large part on whether new polices or strengthened environmental standards will change the economic or regulatory context, causing companies to adopt a more integrated approach to pollutant reduction decisions.

The modeling reveals that if changes in economic or regulatory policy cause a reduction in coal-fired generation, there will be a significant rise in generation by modern gas-fired combined cycle turbines. These turbines are more efficient, reaching efficiency levels in excess of 50% compared to 34% for coal boilers, and emit far less pollution. The major benefits of switching to modern gas-fired turbines that emit no SO_2 or mercury and emit NO_x at only 15 parts per million (ppm)(0.06 lb/mmBtu), are illustrated in the figure below.

Table 2. Criteria Pollutant Emissions of Different Power Generating Sources (lb/MWh)



Sources: EPA, 1998, Compilation of Air Pollutant Emission Factors, AP-42; General Electric, 1999 *Gas Turbine Emissions*. [Note: The coal-fired boiler is assumed to fire low-sulphur coal at 0.5 lb/mmBtu SO_2 and to comply with a Title IV Phase II standard of 0.40 lb/mmBtu NO_x.]
Gas CC = Gas Turbine Combined Cycle;
IGCC = Integrated Coal Gasification Combined Cycle.

ECONOMIC CONTEXT

In 1998, most U.S. energy was produced using coal (51%), followed by nuclear (20%), natural gas (15%), and renewable energy sources, mostly hydroelectric (11%).[14] Energy from coal-fired generation is primarily produced by plants built before 1980 and which emit relatively high levels of air pollutants and greenhouse gases. There has been relatively little retirement of coal-fired power plants in the 1990s,[15] slowing the transition to a more efficient and cleaner power fleet. Economic factors in many regions favor high utilization of these older coal-fired units as the least expensive means of providing base load capacity. Because the capital costs of these older plants have been paid off, they produce electricity only for the cost of fuel, operation and maintenance. The low price of coal has resulted in a national average generation cost of 2.1¢/kWh,[16] lower than virtually all other sources.

The economic situation is different for new electric generating plants, with about 90% expected to be natural gas-fired power plants,[17] which emit much smaller quantities of pollutants and greenhouse gases than coal-fired plants. New gas-fired plants produce electricity at relatively low prices, approximately 3 to 3.5¢/kWh including capital costs, whereas a new coal-fired plant is estimated to cost approximately 4.1¢/kWh including capital costs.[18] Thus, although the current economics of new plants favor the relatively clean and energy-efficient gas-fired systems, older coal-fired plants persist.

An economic policy that would lead to increased switching from coal to gas-fired generation would need to overcome the small difference between the cost of generating electricity from old coal plants and new gas plants. Some empirical evidence suggests that this gap may be closer to a half cent per kWh than a full cent,[19] indicating that a relatively small economic incentive or tax could be enough to tip the scales in favor of gas.

REGULATORY CONTEXT

The federal standards, or absence thereof, applicable to the electrical power industry for major air pollutants and greenhouse gases are summarized below, together with legislative or regulatory proposals that would require major emissions reductions. For each pollutant, we also indicate the pollution reductions that would be created under the 50% coal reduction scenario modeled in this report.

Nitrogen Oxides. Currently, most existing power plants are regulated under rate-based standards set under Title IV of the CAA that relate to the particular combustion technology used by the plant.[20] New major sources must comply with strict New Source Review standards.[21] Significant additional NO_x reductions, however, may soon be required under EPA's NO_x State Implementation Plan (SIP) rule.[22] Also, because NO_x is a precursor to ozone, NO_x reductions may also be necessary in order to meet a proposed more stringent NAAQS for ozone.[23] The coal reduction scenario would achieve approximately 70% of the seasonal NO_x reductions called for under the SIP rule,[24] and would additionally reduce overall national emissions of NO_x by 40%, creating major reductions in particulates and haze.

Sulfur Dioxide. Title IV of the CAA regulates all electric generating sources that have a capacity of 25 MW or greater and caps their collective sulfur dioxide (SO_2) emissions at 8.95 million tons. Although this has achieved a 10 million ton reduction from 1980 levels, there is evidence that additional reductions would create significant health benefits and may be necessary to protect sensitive ecosystems in Canada and the Northeastern states. As a consequence, some legislators, particularly from the Northeastern states, have introduced bills calling for additional reductions of SO_2 on the order of 50% below the existing Title IV cap.[25] The coal reduction scenario would achieve the entire 50% of additional SO_2 reductions called for in these bills.

Particulate Matter (PM). Current regulation for PM only restricts emissions of PM smaller than 10 microns. In 1997, EPA revised the NAAQS for fine particulate matter to set an ambitious new standard for regulating fine particulate matter smaller than 2.5 microns. Like the new NAAQS for ozone, this rule is presently in litigation, and its potential effective date remains uncertain.[26] The coal reduction scenario would produce significantly smaller amounts of fine particulates because it reduces SO_2 and NO_x emissions by 6.8 million tons below business-as-usual levels.

Mercury and Other Hazardous Air Pollutants. Most electric generating sources, but especially coal-fired sources, produce a significant number of hazardous air pollutants, including mercury.[27] Although EPA has not yet addressed hazardous air pollutants generated by power plants, EPA is moving towards regulating mercury emissions from power plants. The coal reduction scenario would achieve a 75% reduction in mercury below 1998 levels.

Carbon Dioxide (CO_2). CO_2 presently is not regulated under U.S. environmental laws but, as a greenhouse gas, covered under the Framework Convention on Climate Change. The United States, together with other developed nations, has agreed to a non-binding commitment to reduce greenhouse gas emissions to 1990 levels by 2000 under that Convention, but few nations have attained this goal. Binding targets for further reductions of greenhouse gases are contained in the Kyoto Protocol to the Convention, which has not been ratified by the U.S. Senate. In addition, proposed legislation calls for reducing CO_2 emissions from the power sector to 1990 levels.[28] The coal reduction scenario would achieve over 100% of the reductions needed to return the electricity generating sector's emissions to 1990 levels.

Although switching to gas-fired generation would go a long way towards addressing these many major air pollution reduction goals, firms currently only face a regulatory mandate to further reduce summertime NO_x emissions in eastern states. This requirement may lead firms to add controls to coal plants, but by itself is unlikely to lead firms to switch to gas generation. Uncertainty as to the timing of other proposed regulatory initiatives means that even those create few present incentives for a more multi-pollutant approach to a compliance strategy. Therefore, whether or not regulatory forces lead firms to switch to gas-fired generation is likely to depend on the stringency as well as the timing of future regulatory initiatives.

THE CONTEXT OF POLICY CHANGE

The above analysis shows that there are two complementary policies that could lead companies to switch from coal to gas-fired generation: economic and regulatory. Economic forces alone would lead to such a switch if the final small difference between the cost of generating electricity from old coal plants and new gas plants could be overcome, such as through an economic incentive or tax policy.[29] A regulatory policy change could also lead firms to switch from coal to gas-fired generation, depending on the stringency, timing and nature of the standards for each pollutant.

III. Assumptions and Uncertainties in the Modeling Exercise

This paper analyzes the benefits and costs of reducing the use of coal for electric generation in the United States by 25% by the year 2005 and 50% by the year 2010. (See Appendix A for more detail.) The analysis of benefits is limited to the benefits of particulate reductions, and does not account for those associated with reductions in ozone levels, acid deposition, mercury contamination and carbon dioxide emissions. In addition, the analysis does not address the environmental costs or benefits associated with lowered coal extraction or increased gas extraction. The analysis of costs is limited to those incurred within the electricity generating sector, and does not address potential general equilibrium effects throughout the economy.

The analysis calculates the amount of coal-fired generation in 1998 as a benchmark, and against this benchmark measures change in coal-fired generation in the years 2005 and 2010. Technical parameters are set to reflect midpoint assumptions by the Energy Information Administration of the Department of Energy[30] and other organizations regarding technological change, growth in transmission capacity, and a number of other factors.

All scenarios assume no change in economic regulatory policy toward the electricity industry beyond that adopted by states as of 2000, with the important exception that under the coal reduction scenario the annual cap for SO_2 emissions established under Title IV of the CAA is reduced in proportion to the reductions in coal-fired generation.[31] This allows the benefits of switching from coal to sulphur-free fuels to be achieved. For NO_x, all scenarios assume a seasonal NO_x cap in the northeast OTC region, but no other NO_x controls beyond those in Title IV of the CAA.[32] To the extent this assumption does not anticipate changes in regulation of NO_x that are likely or already underway, it will overstate the relative competitiveness of existing coal-fired generation, and hence will lead to an overestimate of the cost of reducing coal-fired generation. Both scenarios also assume there is no regulation of CO_2 emissions.

Uncertainties also stem from the large changes in fuel use projected, as well as the underlying uncertainties in the models. Major sources of uncertainty include forecasts of fuel prices, especially natural gas, siting problems that may arise with the need to construct new pipelines and gas power plants, and the cost of capital for individual firms and regions that may face large construction programs to achieve compliance.[33] These factors could potentially increase the cost of the coal reduction scenario. On the other hand, rapid technological progress in the natural gas industry,[34] or increased installation of combined heat and power plants, could help to reduce costs and infrastructure needs of the transition to gas power.

There are also uncertainties in the assessment of the health benefits from particulate reductions. The TAF model employs conservative assumptions relative to the EPA in this regard, reflecting the best judgment of researchers at Resources for the Future with respect to the current literature. The direction of bias resulting from uncertainties affecting the health endpoints that are modeled is ambiguous, but the uncertainties remain substantial. In addition, there are major benefits from emission reductions that are not modeled, and their inclusion would add significantly to the social benefits.

Finally, although this study reports on a scenario that is not embodied in any currently pending policy proposal, it represents an integrated approach that could meet many of the regulatory and legislative initiatives that require reductions in specific pollutants. We emphasize that the regulatory mechanism used to achieve these goals – the choice between technology standards, traditional rate-based standard or stringent but more flexible instruments such as generation performance standards or emission cap and allowance trading programs – is of immense importance to the ultimate cost of these proposals. These limitations are the subject of ongoing programs of research at the Environmental Law Institute and Resources for the Future.

IV. Results

This report compares a business-as-usual scenario with one in which coal fired electricity generation is reduced by 25 percent of baseline (1998) levels in 2005 and by 50 percent in 2010. The results show that the coal reduction scenario results in very significant pollutant reductions, as well as a relatively small percentage rise in electricity prices of 0.33 cents in 2005 and 0.63 cents in 2010, compared to a business-as-usual scenario. All results are in 1997 dollars.

A. Generation by Fuel Type

Under the coal reductions scenario, even though coal-fired generation is reduced by 50%, total generation grows significantly from 3,404 billion kWh in 1998 to 4,051 billion kWh in 2010, only 2 percent below business-as-usual levels. As required by the analytical framework, coal utilization falls 50% from 1,781 billion kWh in 1998 to 889 billion kWh in 2010. The replacement generation under the coal reduction scenario is provided primarily (95%) through a major increase in gas-fired generation, and to a much lesser degree (5%) by increased wind generation. Oil-fired generation declines under all scenarios.

Table 3: National Generation by Fuel and Electricity Price under Business-as-usual and Coal Reduction Scenarios for 2005 and 2010 (Million MWh; $1997).

Fuel Type	1998	2005		2010	
	Baseline	Coal Reduction	BAU	Coal Reduction	BAU
Coal	1,770	1,327	1,770	889	1,805
Gas	469	1,288	1,056	2,061	1,267
Oil	162	21	8	7	3
Hydro	305	305	305	305	305
Nuclear	654	673	670	685	683
Wind	5	33	13	59	17
Other	22	30	22	33	22
Total Generation	**3,404**	**3,690**	3,863	**4,051**	4,121
Electricity Price $/kWh)	**$.0673**	**$.0665**	$.0632	**$.0663**	$.0600

B. Electricity Price

A major finding of this analysis is that electricity price in the coal reduction scenario is 6.63 cents per kWh in 2010, only six tenths of a cent (ten percent) above the business-as-usual scenario. This price is actually one tenth of a cent lower than the 1998 baseline electricity price of 6.73 cents per kWh. The reason for the lower prices in both the business-as-usual and the coal reduction scenarios is the expected price reduction from an increasingly competitive power generation market.

The model also calculates the change in the cost of electricity generation, which is the sum of variable costs (fuel, O&M, general and administrative costs) and the annualized capital charge for new investments. The price of generating electricity reflects the same absolute increase as the overall price, rising 0.65 cents from 2.13 cents per kWh in the business a usual scenario to 2.78 cents in the coal reduction scenario in 2010. However, the percentage change in generation cost is greater since the overall price includes transmission and distribution costs, which do not change.[35]

Several items of empirical data support the finding that a switch from old coal to new gas generation may result in a six tenths of a cent rise in the price of electricity. First, we note that a significant switch from coal to gas-fired generation occurred in the United Kingdom during the 1990s, when over 40% of the UK's coal-fired generation was replaced by new gas-fired generation.[36] During this decade, the price of electricity to industrial users actually fell by 4% in nominal terms and 30% in real terms.[37] Second, the prices being paid for existing coal-fired facilities in the U.S. has been in the neighborhood of $300-400 per kilowatt of capacity.[38] Assuming an 80% load factor, that translates to an expected return of 0.5 cents per kWh on an annualized basis[39]. Presumably, this market valuation of older power plants equals their cost advantage over alternative sources such as new generation, indicating that a half cent per kWh price increase would be the expected result of switching to new gas-fired sources.

C. Changes in Nameplate Capacity

To make up for the lost coal-fired generation, total capacity for natural gas-fired generation rises from 105,000 MW in 1998 to 378,000 MW in 2010. This rise is led by increased combined cycle capacity from 18,000 to 287,000 MW, while single cycle combustion turbine capacity remains constant at around 90,000 MW, although much existing single cycle capacity is replaced. Almost all of this growth represents new construction: 274,000 MW of combined cycle capacity and 49,000 MW of single cycle combustion turbines are built. However, because both scenarios result in a major addition of new gas-fired capacity, the coal reduction scenario results in only a 24% net increase in new gas-fired generation in comparison to business-as-usual levels.

Despite the reduction in coal-fired generation, relatively few coal plants are retired, and total nameplate capacity for coal falls only ten percent from 321,000 MW to 293,000 MW in 2010. This indicates that firms would prefer to maintain existing coal plants at low utilization rates to provide capacity reserve services, rather than retire them.

Table 4a: Total Generation Capacity by Fuel under Different Scenarios for 2005 and 2010.

	Capacity 2005 (thousand MW)			**Capacity 2010** (thousand MW)		
	Coal	Gas	Total	Coal	Gas	Total
Benchmark (1998)	321	105	773	321	105	773
Business-as-usual	319	239	868	321	304	922
Coal Reduction	308	260	897	293	378	997

Table 4b: New Generation Capacity by Fuel under Different Scenarios for 2005 and 2010.

	New Capacity 2005 (thousand MW)				**New Capacity 2010** (thousand MW)			
	Coal	Wind	Gas	Total	Coal	Wind	Gas	Total
Business-as-usual	1	3	165	170	4	4	242	251
Coal Reduction	1	10	190	202	2	19	322	354

D. Energy Consumption by Fuel Type

As expected, consumption of energy from coal falls from 18.8 to 9.3 quadrillion Btu (quads), and energy used for gas-fired plants in 2010 rises from 8.9 to 14.9 quads. The reason that 6 quads of gas can replace 9.5 quads of coal is that gas-fired turbines are about 50% more efficient than coal plants, so overall energy use declines from 35.5 quads under business-as-usual to 32 quads in the coal reduction scenario. The greater efficiency of the gas units is such that even in relation to the 1998 baseline, total energy consumption declines by 1.8 quads, although consumption of gas rises.

Table 5. Energy Consumption under Business-as-usual and Coal Reduction Scenarios

Energy Consumption (Quadrillion Btu)	1998	2005		2010	
	Baseline	Coal Reduction	BAU	Coal Reduction	BAU
Coal	19.0	14.0	18.8	9.3	18.8
Gas	5.3	10.0	7.8	14.9	8.9
Oil	2.1	0.2	0.1	0.1	0.0
Nuclear	6.9	7.1	7.0	7.2	7.2
Total Energy Consumed	**33.8**	**31.9**	34.2	**32.0**	35.5
Total Generation (MMWh)	**3,404**	**3,690**	3,863	**4,051**	4,121

E. Natural Gas Prices to Utilities and Infrastructure Requirements

The change in utilization of coal in the coal reduction scenario has important effects on fuel demand and price, as well as the need to supply and deliver greater amounts of natural gas. The Haiku model uses a reduced form representation of fuel supply for coal and natural gas by supply and demand regions, drawn from the EIA's National Energy Modeling System. However, the significant increase in demand for natural gas in the coal reduction scenario requires extrapolations that must be viewed as uncertain.

The 50 percent reduction in coal-fired generation under the coal reduction scenario leads to a 20 percent reduction in the average price of coal delivered to utilities compared to a business as usual scenario by 2010, from $1 per mmBtu to $0.80 per mmBtu. Also under the coal reductions scenario, natural gas-fired generation increases by roughly 60 percent, leading to a 21 percent increase in the average price of natural gas delivered to utilities, from $3.30 per mmBtu in the BAU scenario to $4 per mmBtu.[40]

Although the price estimates for natural gas in both scenarios are uncertain, they may be conservative, as we note that despite repeated predictions of rising prices, the delivered price of gas to electric generators has remained remarkably low, around $2.50 per mmBtu, throughout the 1990s.[41] Although gas prices have recently spiked to the $4 level,[42], the price is expected by many analysts to remain in the $2.50 to $4.00 range in the foreseeable future.[43] Therefore, the estimates of natural gas prices rising to $3.30 in the BAU scenario and $4 in the coal reduction scenario are reasonable, and may even overstate the expected rise in gas prices and consequent rise in electricity price.

Closely related to the price of natural gas are considerations of availability and supply. Supply considerations depend on whether the very large amounts of natural gas in the ground can be extracted and marketed at an economic price. Here, even the most conservative estimates show that there is 60 years of supply in North America, and hundreds of years if international reserves can be tapped.[44] Furthermore, technology advances that would allow increased exploitation of the enormous amounts of gas in unconventional resources would extend U.S. supplies for hundreds of additional years.[45]

Deliverability of additional supplies of natural gas is also an issue, as it requires potential expansion of U.S. pipeline capacity. However, part of the increase in natural gas demand for electricity generation can be met by levelizing the load on existing pipeline capacity, which is winter peaking in comparison to the summer-peaking electricity load.[46] In addition, U.S. pipeline capacity has already shown it can expand by an average of more than 4 percent a year in 1991 through 1993,[47] which may be more than what is required to meet the coal reduction scenario.

In sum, although the issues of supply and availability of gas present important considerations, market forces appear able to resolve them. The U.S. Energy Information Administration concludes: "Overall, the natural gas industry is thought to be in a position to meet the supply requirements for a market of 30 trillion cubic feet, with adequate supplies from numerous sources at the prices projected in thee *Annual Energy Outlook 2000* reference case. As long as the industry remains confident that the demand will be there, the economic incentive of higher prices will assure that the necessary investment in infrastructure, rigs, drilling and manpower will be made."[48]

F. Pollutant Emissions

The change in choice of technology for generation yields a major reduction in pollutant emissions from coal-fired generation, compared to business-as-usual levels (Table 6). SO_2 emissions are cut in half by 2010, falling from 9 million to 4.4 million tons, reflecting the modeling instructions that allow SO_2 to fall proportionally to reduction in coal usage. NO_x reductions fall from 5.5 million tons to 3.3 million tons, a 40 percent reduction. In the case of both SO_2 and NO_x, these reductions are over and above those occurring in a business-as-usual scenario, in which emissions are below the 1998 baseline due to implementation of Phase II of the Title IV Acid Rain Program. Carbon emissions also fall significantly from 670.5 million to 498.6 million tons, reducing utility emissions to below their 1990 level of 524.4 million tons.[49]

Mercury emissions reductions were separately calculated based on average mercury content of coal, differentiated by fourteen coal supply regions, coupled with coal demand modeled by Haiku. Although we calculate differences in the mercury content of coal, estimating mercury emissions remains uncertain, as some control technologies also reduce mercury emissions,[50] transferring the mercury to solid and liquid wastes: our estimates assume a 20% removal rate from coal washing of eastern bituminous coals, and a 50% reduction in emissions through flue gas desulphurization (scrubbing) technologies.[51] We note that mercury emissions fall even in the BAU case from the 1998 baseline level because of the tightening cap on SO_2 emissions under the Acid Rain Program. In the coal reduction scenario, mercury emissions fall to 48% below BAU levels by 2005 and 58% by 2010.[52]

Table 6. Pollutant Emissions under Business-as-usual and Coal Reduction Scenarios

Pollutant Emissions	1998	2005		2010	
	Baseline	Coal Reduction	BAU	Coal Reduction	BAU
SO_2 (thousand tons)	12,790	**7,668**	10,110	**4,407**	8,999
NO_x (thousand tons)	5,934	**4,430**	5,521	**3,298**	5,515
CO_2 (thousand tons carbon equivalent)	663,100	**557,600**	651,500	**498,600**	670,500
Mercury (tons)	80	**38**	72	**21**	50

The pollutant reductions achieved by the shift from coal to gas-fired power generation simultaneously address or resolve a number of major air pollutant problems that cause either significant human health and welfare impacts, or damage to ecosystems on a regional or global scale.

Particulate Matter Health Impacts. Because NO_x and SO_2 emissions create fine particulate matter that causes severe human respiratory health problems, the reductions in both of these pollutants under the coal reduction scenario will create major health benefits. These reductions would also go a long way towards compliance with EPA's proposed new National Ambient Air Quality Standard (NAAQS) for fine particulate matter smaller than 2.5 microns, which is currently in litigation.[53]

Acid Deposition. Emissions of SO_2 in particular, but also NO_x, are the cause of acid rain and snow that causes acidification of water bodies and other ecosystem damage, as well as economic losses. The decreased emissions of SO_2 created in the coal reduction scenario would meet the levels called for in bills recently introduced in Congress, which require an additional 50% reduction in SO_2 emissions below Title IV levels.[54]

Visibility Impairments. Particulates derived from emission of SO_2 and NO_x result in haze which causes significant visibility impairments over our National Parks and other areas. The combined 6.8 million ton reductions in these pollutants from business-as-usual levels by 2010 would create major economic and welfare benefits.

Urban Ozone Health Impacts. A primary health problem caused by NO_x emissions is its interaction with volatile organic compounds in summer months to form ground-level ozone, creating health impacts especially for children, the elderly and others with impaired lung function. EPA's State Implementation Plan rule[55] for regulating ozone would require significant NO_x reductions, to meet ambient requirements for ozone. The coal reductions scenario leads to a disproportionately high 46% reduction in NO_x emissions in the SIP call region, achieving approximately 70% of the 66% reduction in electricity sector emissions called for under the SIP rule.[56]

Eutrophication and Agricultural Damage. Deposition of air-borne NO_x, which reaches water bodies, causes eutrophication and especially severe problems in estuaries such as the Chesapeake Bay and Long Island Sound. Affected states have called for significant reductions in NO_x emissions as well as other nitrogen sources. Although nitrogen loading may also stimulate plant growth, this effect is countered by the damage to plants caused by the ozone created from NO_x emissions. EPA estimates that crop damages due to ozone amount to several billion dollars annually.[57]

Impacts of Mercury and other HAPs. Mercury is listed third on EPA's national priority list of toxic substances,[58] and consequently is the focus of a major initiative to reduce emissions as well as overall releases. Mercury emissions from the power sector are currently about one-third of mercury emissions in the US, although regulation has been delayed until EPA concludes an assessment process.[59] The coal reduction scenario lowers mercury emissions 58% below business-as-usual levels, and 74% below baseline 1998 emissions.[60]

Climate Change. Emissions of CO_2, a greenhouse gas, are presently not regulated under U.S. environmental laws, but are now 15% above 1990 levels. [61]Bills introduced in Congress call for a return of CO_2 emissions in the electric generating sector to 1990 levels,[62] and the Kyoto Protocol would require national reductions in CO_2 emissions to 7%

below 1990 levels. The coal reduction scenario would reduce CO_2 emissions from 670.5 million to 498.6 million tons carbon equivalent, achieving over 100% of the reductions needed to return the electricity generating sector's emissions to 1990 levels of 524.4 million tons carbon.

G. Changes in Health Benefits from Particulate Reductions

Public health benefits of $26.4 million are expected from reductions in NO_x and SO_2 due to lowered particulate concentrations (Table 7). The health benefits from particulate reductions due to lowering SO_2 levels are the major component, totaling $24.5 billion for the year 2010. Health benefits from particulates reductions due to lowered NO_x levels are $2.0 billion. Because there are significant uncertainties in the estimation of health benefits along many links in the underlying integrated assessment model, Resources for the Future makes several conservative assumptions.[63] These may lower estimates of benefits in comparison to other studies.[64]

Table 7. Improvements in Public Health from Particulate Reductions under the Coal Reduction Scenario in Comparison to a Business-as-usual Scenario in 2010 ($ billion).

	Morbidity	Mortality	Total
SO_2	1.2	23.2	24.5
NO_x	0.4	1.6	2.0
Total	1.6	24.8	26.4

The health benefits modeled here are only of lowered concentrations of SO_2 and NO_x and lowered particulate concentrations due to the lowered SO_2 and NO_x emissions. They do not include the benefits from lowering these same pollutants in reducing urban ozone levels, or the many other benefits listed above in reducing acid deposition and eutrophication, and increasing visibility. However, recent EPA estimates of total benefits of NO_x reductions for the NO_x SIP call were approximately double the benefits from particulate reduction alone.[65] Nor does this report quantify the benefits from lowering mercury emissions from the power generation sector by 58%, which may be substantial but are difficult to quantify. In addition, a complete benefits analysis should consider the major benefits of reducing carbon emissions by 25% or 172 million tons compared to a business-as-usual scenario, just over a third of the total reductions needed to reduce all national carbon emissions to 1990 levels.

H. Economic Costs Associated with the Coal Reduction Scenario

This report estimates changes in consumer and producer surplus within a partial equilibrium model, that is, changes that occur within the electricity sector of the economy. The estimates made are annual, whereas a complete benefit-cost analysis might consider changes in surplus for a number of years into the future, and discount them to present dollar values. A long-term forecast introduces greater uncertainties, but in the future net costs and benefits could be expected to be lower, as the existing coal plants will be replaced at the end of their useful lives.

Changes in Consumer Surplus

The major economic cost associated with meeting the coal reduction scenario is the six tenths of a cent rise in the cost of electricity to consumers over a business-as-usual scenario. The resulting price of electricity is 6.63 cents per kWh, more than the business-as-usual scenario but slightly lower than the price of electricity in the 1998 baseline. The loss in consumer surplus associated with this price increment is calculated at $25.2 billion in 2010.

Changes in Producer Surplus

The change in producer surplus under the coal reduction scenario is significantly less than the change in consumer surplus, and depends on whether the reduction is achieved by a grandfathering mechanism or by auctioning rights to firms in the industry. If an auction is used to allocate rights to generate with coal or pollutant emissions, the impact on producer surplus is greater because the (marginal cost) regions that trade permits incur added costs, although there is a commensurate transfer of revenue to the government. If rights are grandfathered at no cost, the change in producer surplus is less because the regions that trade permits obtain them at zero cost; there is also no transfer to the government.

Table 8. Changes in Economic Cost compared to Business-as-usual (billion 1997 dollars)

	Consumer	Producer	Government Revenue	Net
Implement by Auctioning	25.2	4.4	3.8	25.9
Implement by Grandfathering	25.2	0.7	0	25.9

General Equilibrium Effects

A full analysis of the changes and costs caused by the coal reduction scenario would call for a “general equilibrium analysis” that considers economic effects throughout the economy, not just in the electricity sector. We have not undertaken an integrated model to estimate general equilibrium effects, which may be as potent as those stemming from consumer surplus. These effects would include those on the coal mining industry, with $23 billion in 1997 revenues,[66] and the railroad industry, which earned $8 billion dollars in 1997 from coal transport.[67] Although these industries have revenues that are an order of magnitude less than the electricity industry, they will suffer substantial lost profitability, and workers in these industries will suffer dislocation and hardship, regardless of whether the losses may be made up in other sectors of the economy.

In addition, there is a potential general equilibrium effect that stems from changes in the labor market caused by any new regulation that affects product prices. Several recent studies have identified that such regulation may cause workers to adjust their choice between labor and leisure, with consequent economic loss. Resources for the Future has estimated these costs could total as much as $8 billion in 2010 in the case of grandfathered permits, and $2.9 billion in the case of auctioned permits.[68] However, offsetting these costs to some degree is the expectation that improvements in public health may lead to increases in labor productivity. These improvements would generate their own set of secondary benefits that also have not been modeled in this investigation.

V. Conclusion

The analysis presented in this report shows that reducing coal-fired generation by 50% by 2010 leads to a relatively smooth transition to natural gas power. Total electricity generation falls only slightly, and the main shifts required are a 25% increase in the construction of new gas plants and in the overall national supply of natural gas. These changes result in higher prices for natural gas and a predicted cost of electricity of 6.63 cents per kWh, six tenths of a cent above business-as-usual levels, but slightly lower in real terms than the 1998 baseline price of 6.73 cents.

The analysis underlines the importance of achieving an integrated approach to the pollutant reductions called for in environmental initiatives facing the power industry. In particular, an integrated approach helps achieve consistency in policies to reduce criteria pollutants, toxics and greenhouse gases. The transition from coal to natural gas power would simultaneously reduce emissions of SO_2, NO_x, mercury and CO_2 in the power sector. These reductions would go a long way towards addressing major pollution problems, including the need to reduce fine particulates, haze, urban ozone levels, acid deposition, greenhouse gases and mercury contamination. Because the existing economic context and pollutant-by-pollutant regulation may only cause firms to address NO_x reductions, additional regulatory or economic incentive mechanisms are needed to achieve such an integrated approach.

The calculated human health benefits of the reductions in particulates alone, $26.4 billion, roughly equal the direct costs of $25.9 billion per year of reducing coal-fired generation by half. Achieving a transition from coal to gas in the near term could eliminate or vastly reduce the cost of attaining many other major air pollution issues faced by the electricity generating sector, including acid rain, urban ozone, toxics and climate change.

Endnotes

1. *Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone*; *Final Rule*, 63 Fed.Reg. 57356 (Oct 27, 1998)(covering 22 states), upheld in *Michigan v. US EPA*, 213 F.3d 663 (D.C. Cir. 2000) (limiting application to 19 states and extending deadline for States to file State Implementation Plans (SIPs) to Oct. 31, 2000).

2. EPA promulgated a stringent new National Ambient Air Quality Standard for ozone, including fine particulate matter smaller than 2.5 microns, 62 Fed. Reg. 38856 (July 18, 1997), but an appeals court later struck down major elements of this rule, *American Trucking Association v. US EPA*, 175 F.3d 1027 (D.C. Cir. 1999), *cert. granted* U.S. No. 99-1927, 5/22/00. Final resolution of these issues is pending, and there may be further delay in implementing additional NO_x reductions.

3. Various legislative proposals would require major emissions reductions in four pollutants from the electric generating industry, either by imposing emission cap and allowance trading systems for the pollutants, *see*, *e.g.*, H.R. 25 sponsored by Rep. Boehlert (R-NY), H.R. 2569, sponsored by Rep. Pallone (D-NJ), and S. 1369, sponsored by Sen. Jeffords (R-VT), or by imposing New Source Performance Standards on existing plants, *see*, *e.g.*, S. 1949, sponsored by Sen. Leahy (D-VT). These bills typically call for additional reductions of SO_2 on the order of 50% below Title IV levels, NO_x reductions of 70-85% below 1990 levels, CO_2 reduction to 1990 levels, and a 90% reduction in mercury emissions from 1990 levels.

4. *See*, *e.g.* US EPA, Mercury Study Report to Congress. EPA-452/R-97-003 (December, 1997); US EPA, Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units -- Final Report to Congress. EPA-453/R-98-004a (February 1998).

5. *See* note 3, *supra*.

6. United Nations Framework Convention on Climate Change [see www.unfccc.de]. If ratified, the Kyoto Protocol to the UNFCCC, FCCC/CP/1997/7/Add.1, would establish a binding greenhouse gas reduction targets of 7 percent below 1990 levels for the United States during the period 2008-2012.

7. US EPA, NATIONAL AIR POLLUTANT EMISSION TRENDS, 1990-1998 (1999).

8. US EPA, STUDY OF HAZARDOUS AIR POLLUTANT EMISSIONS FROM ELECTRIC UTILITY STEAM GENERATING UNITS -- FINAL REPORT TO CONGRESS. EPA-453/R-98-004a (February, 1998).

9. US EIA, EMISSIONS OF GREENHOUSE GASES IN THE UNITED STATES 1998. DOE/EIA-0573(98) at 13, 16 (October, 1999).

10. *See* Union of Concerned Scientists, AMERICA'S ENERGY CHOICES: INVESTING IN A STRONG ECONOMY AND A CLEAN ENVIRONMENT. (Cambridge, MA 1992).

11. This report indicates that new natural gas supplies equivalent to 6 quads (quadrillion British thermal units, equivalent to 5.9 trillion cubic feet of gas) will be needed in 2010 to replace 9.5 quads of coal as fuel for electricity generation. The lower number of quads needed is due to the greater efficiency of gas-fired turbines compared to coal boilers. This represents a 22% increase to the 27.7 quads of estimated total natural gas demand in 2010.U.S. Energy Information Agency, ANNUAL ENERGY OUTLOOK 2000: WITH PROJECTIONS TO 2020 at Table A1. DOE/EIA-0383(2000) (December, 1999) [Hereinafter ANNUAL ENERGY OUTLOOK 2000].

12. This estimate of cost does not include the potential indirect effects of these changes on other sectors of the economy, such as decreased employment and profitability in the coal supply industries, or offsetting increases in the gas supply industries, all of which could be significant.

13. In 1998, most U.S. energy was produced using coal (51%), followed by nuclear (20%), natural gas (15%), and renewable energy sources, mostly hydroelectric (11%). U.S. Energy Information Administration, ELECTRIC POWER ANNUAL 1999 VOLUME I, DOE/EIA-0348(99)/1, at Table 5 (August, 2000).

14. *See* note 13 *supra*.

15. *See* U.S. Energy Information Administration, INVENTORY OF POWER PLANTS IN THE UNITED STATES AS OF JANUARY 1, 1998 (1999).

16. Bruce Biewald, David White, and Tim Woolf, *Grandfathering and Environmental Comparability: An Economic Analysis of Air Emission Regulations and Electricity Market Distortions*. Prepared for the National Association of Regulatory Utility Commissioners by Synapse Energy Economics, Inc. (Cambridge, MA 1998). Another estimate puts the total cost in a range of 1.5¢/kWh to 3¢/kWh. State and Territorial Air Pollution Program Administrators and Association of Local Air Pollution Control Officials (STAPPA/ ALAPCO), REDUCING GREENHOUSE GASES AND AIR POLLUTION: A MENU OF HARMONIZED OPTIONS, at 49 (1999).

17. A principal reason why over 90 percent of new generation is expected to be gas-fired turbines is that new gas-fired turbines produce electricity at 3to 3.5 cents per kilowatt, compared repetitive to 4 cents for a new coal-fired power plant. This cost advantage is expected to last into the next decades despite the rising cost of natural gas. ANNUAL ENERGY OUTLOOK 2000, at 67, 70.

18. ANNUAL ENERGY OUTLOOK 2000, at 67 (1999). STAPPA/ALAPCO estimated the cost of electricity generated by a new combined cycle gas plant to range from 3¢ to 4.5¢ per kWh. STAPPA/ALAPCO, at 49. Biewald *et al.* estimated the costs to range from 3.1¢ to 6.1¢ per kWh, depending upon the capacity factor.

19. *See* text at notes 36-39, *infra*.

20. Title IV imposes NOx emissions limits of from 0.40 lb/mmBtu to 0.84 lb/mmBtu on coal-fired boilers depending on the boiler technology. 42 U.S.C. §7651f.

21. Major new sources or major modifications of existing sources must comply with stringent standards in a process called New Source Review. Those built in areas that have attained the ambient ozone standard set by EPA must prevent significant deterioration of air quality, and install the Best Available Control Technology (BACT), defined as the best control technology considering "energy, environmental, and economic impacts and other costs". 42 USC §§7475, 7479(3). New sources in non-attainment areas must install Lowest Achievable Emissions Reduction (LAER) technology for the kind of plant proposed. 42 USC §7503 (a)(2).

22. In October 1998, EPA issued a final rule calling for 22 states and the District of Columbia to revise their State Implementation Plans to provide for further reductions in NO_x emissions, and to implement a cap and trade program. 63 Fed. Reg. 57356 (1998). This rule, known as the "NO_x SIP call," was substantially upheld in a ruling on March 3, 2000. *Michigan v. U.S. Environmental Protection Agency*, 213 F.3d 663 (D.C. Cir. 2000). The situation remains somewhat unclear, especially with respect to timing.

23. EPA promulgated a new NAAQS for ozone, 62 Fed. Reg. 38856 (July 18, 1997), but this rule was stayed by a three-member panel of the Court of Appeals for the District of Columbia Circuit, *American Trucking Associations, Inc., v. U.S. Environmental Protection Agency*, 175 F.3d 1027 (1999). Upon a petition for a rehearing, this ruling was later vacated in part, *American Trucking Associations, Inc., v. U.S. Environmental Protection Agency*, 195 F.3d 4 (1999). Final resolution of these issues is pending, and there may be further delay in the implementation of additional NO_x restrictions.

24. *See* note 55, *infra*. The model shows that NOx emissions would be reduced 46% in a region that approximates the SIP region, disproportionately greater than the overall level of national NOx reductions.

25. *See* note 3, *supra*.

26. 62 Fed. Reg. 38652 (July 18, 1997). This rule was remanded to the Agency in the same proceedings as those for the new ambient standard for ozone, *American Trucking Associations, Inc., v. U.S. Environmental Protection Agency*, 175 F.3d 1027 (1999) and *American Trucking Associations, Inc., v. U.S. Environmental Protection Agency*, 195 F.3d 4 (1999).

27. *See* generally, USEPA, STUDY OF HAZARDOUS AIR POLLUTANT EMISSIONS FROM ELECTRIC UTILITY STEAM GENERATING UNITS -- FINAL REPORT TO CONGRESS. EPA-453/R-98-004a (February 1998).

28. *See generally* ANNUAL ENERGY OUTLOOK 2000 at 37-46.

29. *See generally*, Environmental Law Institute, *The Potential Role of Incentives in a Clean Energy Future: An Expert Dialogue* (April, 2000).

30. *See* ANNUAL ENERGY OUTLOOK 2000.

31. Title IV, established in the 1990 CAA Amendments, establishes an annual average national cap of approximately 9 million tons of SO_2 emissions on the electric power industry, commencing in 2000. 42 U.S.C. 7651 *et seq*. In order to capture sulphur reductions achieved by a reduction in coal-fired generation, the cap established under Title IV would need to be reduced proportionally through a political process.

32. 42 USC §7651f (establishing technology-based rate limits for existing coal plants).

33. Another potentially important assumption is that we do not allow for co-firing of biomass with coal. If biomass co-firing were allowed, it would be likely to increase slightly the generation from coal capacity and lessen the economic cost of the coal reduction scenario. Biomass would have additional emissions of NO_X, but no SO_2, and little CO_2 when the biomass is viewed from a life-cycle perspective.

34. See generally, Environmental Law Institute, HOW ABUNDANT? ASSESSING THE ESTIMATES OF NATURAL GAS SUPPLY (Washington, D.C., May 1999).

35. The generation cost increases by a very small amount more than total electricity price in the coal reduction scenario because marginal units are relatively less affected than infra-marginal units, while average costs have changed substantially.

36. European Commission, Directorate for Energy, ENERGY IN EUROPE:1999 - ANNUAL ENERGY REVIEW at part II, page 54 (January, 2000) (between1990 and 1997, UK coal generation fell from 47.6 to 27.1 gigawatts, while gas-fired generation rose from 1.6 to 19.2 gigawatts).

37. UK Electricity Association data (available at www.electricty.org/uk) (average electricity prices to industrial users in the UK fell from 4.67 pence per kWh in 1989/90 to 4.50 pence per kWh in 1998/99, a 30% decrease in real terms as the UK Retail Price Index rose from 117 to 164 during that period).

38. Electric Power Research Institute, *From the Director - High Fossil Plant Prices are Surprising*, EPRI Fossil Plan News (Winter 1999); Kahn, Edward P. *A Folklorist's Guide to the Used Power Plant Market*, The Electricity Journal at 66 (July 1999).

39. Net generation is 7,008 kilowatt hours per year at an 80% capacity factor, so a price of $350 per kilowatt of capacity is equivalent a capitalized value of 5 cents per kWh, or 0.5 cents per kWh on an annualized basis using an 11% discount rate.

40. All prices are in 1997$.

41. US Energy Information Administration, NATURAL GAS MONTHLY AUGUST 2000 (September 14, 2000). Over the past decade, the Dept. of Energy has consistently predicted rises in gas prices that considerably exceed the actual fact. *See generally*, Environmental Law Institute, HOW ABUNDANT? ASSESSING THE ESTIMATES OF NATURAL GAS SUPPLY, at 11 (Washington, D.C., May 1999).

42. US Energy Information Administration, NATURAL GAS MONTHLY AUGUST 2000 at 4-6 (September 14, 2000).

43. The US EIA's reference case forecast is for a delivered price to electric generators of $3.14 per thousand cubic feet ($3.20 per mmBtu) in 2010, and $3.41 ($3.48 per mmBtu) in 2020, both about 20% higher than the wellhead price. ANNUAL ENERGY OUTLOOK 2000, table A14. *See also*, Henry Lee and Shashi Kant Verma, *Coal or Gas: The Cost of Cleaner Power in the Midwest* (Harvard Univ., June 2000)(predicting future wellhead prices between $2.50 and $3); Environmental Law Institute, HOW ABUNDANT? ASSESSING THE ESTIMATES OF NATURAL GAS SUPPLY (Washington, D.C., May 1999). The potential contribution of international resources is also very large if technology can reduce the price of gas liquification, as there are over 5,000 trillion cubic feet in international proved reserves. U.S. Energy Information Administration, INTERNATIONAL ENERGY OUTLOOK 1998. DOE/EIA-0484(98) (April, 1998).

44. U.S. Energy Information Administration, U.S. CRUDE OIL, NATURAL GAS, AND NATURAL GAS LIQUIDS RESERVES 1997 ANNUAL REPORT (March, 1998) (estimates limited to existing geological information and foreseeable technologies).

45. *See, e.g.*, American Gas Foundation, FUELING THE FUTURE: NATURAL GAS AND NEW TECHNOLOGIES FOR A CLEANER 21ST CENTURY; Environmental Law Institute, HOW ABUNDANT? ASSESSING THE ESTIMATES OF NATURAL GAS SUPPLY (Washington, D.C., May 1999).

46. ANNUAL ENERGY OUTLOOK 2000 at 23-24.

47. *Id.*

48. *Id*. at 30.

49. U.S. Energy Information Administration, EMISSIONS OF GREENHOUSE GASES IN THE UNITED STATES 1998 at 16. DOE/EIA-0573(98) (October, 1999) (1990 emissions of the electric utility sector are 476.7 million metric tons carbon, or 524.4 million short tons).

50. Center for Clean Air Policy, *Mercury Emissions from Coal-Fired Power Plants: Science, Technology and Policy Options* (November, 1998).

51. In both cases, the mercury is simply transferred to solid or liquid wastes, where it may eventually re-emit; however, the mercury reductions achieved through the coal reduction scenario however are real reduction achieved through pollution prevention, though switching to gas-fired generation.

52. The reductions in mercury emissions are not equivalent to the reduction in coal-fired generation due to different kinds of coal used and the percentage of scrubbed plants used.

53. *See* note 2, *supra*.

54. *See* note 3, *supra*.

55. *See* note 1, *supra*.

56. The SIP call regulation suggests that states could achieve the required NO_x reductions primarily by reducing NO_x emissions from electric generating sector from 1,501,800 to 543,825 tons, a 64% reduction. 63 Fed. Reg. 57434 (Oct. 27, 1998). The modeling results show that NO_x emissions are reduced in the five NERC regions equivalent to the SIP call region (ECAR, MAAC, MAIN, NPCC AND STV) from 3,486,00 annual tons in a business as usual scenario to 1,884,000 annual tons in the coal reduction scenario, a 46% reduction. This reduction is 72% of the total percentage reduction called for in the SIP regulation.

57. *See*, US EPA, BENEFITS AND COSTS OF THE CLEAN AIR ACT: FINAL REPORT TO CONGRESS ON BENEFITS AND COSTS OF THE CLEAN AIR ACT, 1970 TO 1990, EPA 410/R/97/002 (1997).

58. Agency for Toxic Substance and Disease Registry (in cooperation with US EPA), 1997 CERCLA Priority List of Hazardous Substances (November, 1997) (mercury is third overall).

59. *See generally* US EPA, MERCURY STUDY REPORT TO CONGRESS, EPA-452/R-97-003 (December, 1997); US EPA, STUDY OF HAZARDOUS AIR POLLUTANT EMISSIONS FROM ELECTRIC UTILITY STEAM GENERATING UNITS -- FINAL REPORT TO CONGRESS, EPA-453/R-98-004a (February 1998).

60. We note that the reductions in mercury from the coal reduction scenario are largely real and permanent as a consequence of shifting to gas-fired generation. Such reductions are environmentally preferable to those achieved through emission controls due to the persistence and volatility of mercury, in that controls simply transfer the mercury to solid and liquid wastes, where it may be expected to eventually re-enter the environment.

61. "Carbon emissions from energy consumption are expected to reach 1,552 million metric tons in 2000, 15 percent above the 1990 level of 1,345 million metric tons [MMT]. The projected emissions continue to rise to 1,787 million metric tons in 2010...33% above 1990 levels." ANNUAL ENERGY OUTLOOK 2000 at 37. Carbon emissions from electric generating units account for about one third of this total, accounting for 476.7 MMT (524.4. short tons) in 1990. US EIA, GREENHOUSE GAS EMISSIONS, *supra* note 49, at 16.

62. *See* note 3, *supra*.

63. These include, for example, valuing a statistical human life at $3.8 million, which is lower than EPA's estimate of over $5 million. Recent evidence in the literature also may point in the direction of a moderate reduction in the estimates of health benefits as they are represented here (Krupnick et al. 2000).

64. A recent study by the Clean Air Task Force uses EPA methodology and derives benefits of over $100 billion from particulate reductions if pollutants from coal-fired plants are reduced by 75% , a greater reduction than the reduced generation modeled in this study. Clean Air Task Force, *Death, Disease & Dirty Power: Mortality and Health Damage Due to Air Pollution from Power Plants* (October, 2000).

65. *See* U.S. Environmental Protection Agency, REGULATORY IMPACT ANALYSIS FOR THE NO_X SIP CALL, FIP, AND SECTION 126 PETITIONS- VOL. 2: HEALTH AND WELFARE BENEFITS. EPA-452/R-98-003 at ES-6 (December,1998).

66. U.S. Census Bureau, STATISTICAL ABSTRACT OF THE UNITED STATES: 1999, Table 872 (2000) (information on receipts in the coal mining industry).

67. Association of American Railroads, THE RAIL TRANSPORTATION OF COAL, Washington DC (January, 2000).

68. The costs created by an auction mechanism are lower because they provide revenues for the government that can be used to lower pre-existing distortionary taxes. *See, e.g.*, Goulder, Lawrence H., Ian W. H. Parry, Roberton C. Williams III and Dallas Burtraw. "The Cost-Effectiveness of Alternative Instruments For Environmental Protection in a Second-Best Setting," *Journal of Public Economics*, vol. 72, no. 3 (June, 1999), 329-360.

APPENDIX A

Description of Haiku Electricity Market Model and the Tracking and Analysis Framework, and Definitions and Assumptions Made in the Modeling Exercise

The investigation makes use of the Haiku electricity market model developed and maintained at Resources for the Future. This model estimates equilibria in the electricity market, including changes in the investment and retirement of specific technologies on a regional basis. The model also calculates changes in emissions, which are passed to the Tracking and Analysis Framework (TAF) to estimate changes in atmospheric concentrations of particulates and their health effects, and to value those changes in monetary terms that can be compared with the cost of electricity generation. A description of how the scenarios were constructed and of key assumptions made in this task and the models are described below.

HOW THE COAL PHASE-OUT SCENARIO IS CONSTRUCTED

Under the coal phase-out scenario, coal fired electricity generation is reduced to 75 percent of benchmark (1998) levels in 2005 and to 50 percent of benchmark levels in 2010. This reduction is achieved in different ways in average and marginal cost regions. In average cost regions operating under traditional cost of service regulation, the required reduction in coal-fired generation is achieved within each region. However, individual model plants may reduce by less or more than the aggregate percentage reduction required. As a result plants with the most expensive generation within a region are the first to reduce generation. The mandated percent reductions are applied uniformly to all average cost regions.

The effect on price in average cost regions is similar to what would occur with the use of "economic adders" to represent the environmental damages of different technologies and fuels that was widely considered and implemented by several state PUCs in the industry in the early 1990s. Specifically, it is assumed the regulator can accurately observe the percent of coal-fired generation and the variable costs of production, and can enforce the required phase-out in a cost-effective manner. The increased variable and capital costs stemming from the use of alternative facilities, as well as the potentially stranded capital cost of coal-fired capacity, are recovered in the average price of electricity. However, there is no additional cost such as the price of a tradable permit included in the price, though presumably such an accounting instrument would be used inside the region to identify the merit order for dispatch among facilities.

In marginal cost regions the electricity price is determined not by the regulator but at the competitive margin, and there is no possibility for a regulator to observe and enforce a dispatch order in generation. Consequently we introduce "tradable coal generation permits" that are capped at the allowed maximum level of generation. This approach differs from that applied to average cost regions in two ways. First, the cost of tradable generation permits is reflected as a variable cost and directly influences marginal cost along with the cost of alternative facilities that are used to achieve compliance. Second, these permits are tradable among marginal cost regions, but not average cost regions, which introduces greater flexibility among marginal cost regions.

IMPORTANT ASSUMPTIONS MADE IN THE MODELING EXERCISE

We make important assumptions in the modeling exercise that potentially affect results. One is that we do not allow co-firing of biomass with coal. If biomass co-firing were allowed, it would be likely to increase slightly the generation from coal capacity and lessen the economic cost of the coal reduction scenario. Biomass would have additional emissions of NO_X, but no SO_2, and little CO_2 when the biomass is viewed from a life-cycle perspective.

The model also uses a constant cost of capital reflecting current expectations of the opportunity cost of capital consistent with those embodied in several other electricity models including that maintained by the Energy Information Administration. However, the scenario we model may impose large construction programs on some firms in some regions of the country. Also, the imposition of a single or set of policies that led to the scenario we model could affect the actual or perceived regulatory uncertainty faced by firms in the future. These changes could lead to an increase in the cost of capital for individual firms and regions above the average values that are used in the business-as-usual scenario.

In all scenarios, we assume no change in economic regulatory policy toward the electricity industry beyond that adopted by states in the region as of 2000. The schedule for transition away from cost of service to market based pricing by region is reported in Table 1. In all scenarios, we assume NO_x trading in the northeast OTC region, but no other NO_x controls beyond those in Title IV of the 1990 Clean Air Act Amendments. To the extent this assumption does not anticipate changes in regulation of NO_x that are likely or already underway, it will overstate the relative competitiveness of existing coal-fired generation, and hence will lead to an overestimate of the cost of reducing coal-fired generation. We assume there are no policies implemented for CO_2 emissions. However, for SO_2 emissions, the average annual cap established under the 1990 Clean Air Act Amendments is reduced in proportion to reductions in coal-fired generation.

THE HAIKU ELECTRICITY MARKET MODEL

The Haiku electricity market model calculates equilibria in regional electricity markets with inter-regional electricity trade. The model includes a fully integrated algorithm for investment and retirement of generation capacity and for NO_x emission control technology choice and SO_2 compliance. The model simulates electricity demand, electricity prices, the composition of electricity supply, and emissions of key pollutants including NO_x, SO_2, mercury and CO_2 from electricity generation. Generator dispatch in the model is based on minimization of short run variable costs of generation. The model can be used to simulate changes in electricity markets stemming from public policy associated with increased competition or environmental regulation.

Two key components of the Haiku model are the Intra-regional Electricity Market Component and the Inter-regional Power Trading Component. The Intra-regional Electricity Market Component solves for a market equilibrium identified by the intersection of electricity demand for three customer classes (residential, industrial and commercial) and supply curves for each of four time periods (peak, shoulder, middle and baseload hours) in each of three seasons (summer, winter, and spring/fall) within each NERC region.[1] Each regional supply curve is parameterized using cost estimates and capacity information for between 20 and 29 aggregate "model plants" defined by technology, fuel and vintage. The Inter-regional Power Trading Component solves for the level of inter-regional power trading necessary to equilibrate regional electricity prices (gross of transmission costs and power losses). These inter-regional transactions are constrained by the assumed level of available inter-regional transmission capability as reported by NERC.

Because the model solves for uniform reductions among regions, in order to model the coal reduction scenario we allow tradable generation permits among marginal cost regions[2] but not average cost regions operating under traditional cost of service regulation. This allows a slightly more competitive market to develop, but the overall amount of reduction is the same as in a scenario in which all regions achieve the stated 25% and 50% reductions; however, among marginal cost regions the model plants or regions with the highest costs are expected to reduce more than lower cost plants or regions. This has the effect of slightly reducing the compliance cost, but offsetting this is the fact that the opportunity cost of the permits will be reflected in electricity price.

Also, in this analysis we adopt a conservative assumption by assuming that regions that have not committed themselves to a schedule of transition to market-based prices continue with cost of service pricing indefinitely over the study period. The entry into force of marginal coast pricing regimes in the various NERC regions is shown in the table below.

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[1] The current version of the Haiku model includes the 9 NERC regions: NPCC, MAAC, ECAR, SERC, MAIN, MAPP, SPP, ERCOT and WSCC, as they were defined in 1997. Recently, Florida has split from SERC to form its own NERC region, FRCC, but this region is included in SERC for this analysis.

[2] In average cost regions, the mandated percent reductions are applied uniformly to all regions, and the required reduction in coal-fired generation is achieved within each region. However, individual model plants may reduce by less or more than the aggregate percentage reduction required. As a result plants with the most expensive generation within a region are the first to reduce generation. The increased variable and capital costs stemming from the use of alternative facilities, as well as the potentially stranded capital cost of coal-fired capacity, are recovered in the average price of electricity.

Table A-1: The year marginal cost pricing begins under modeled scenarios.

NERC Region	Year Marginal Cost Pricing Regime Begins
ECAR	-
ERCOT	2002
MAAC	2000
MAIN	2001
MAPP	-
NY	1999
NE	2000
FRCC	-
STV	-
SPP	-
NWP	-
RA	2001
CNV	1998

Further, we distinguish two cases that depend on how tradable generation permits in the marginal cost regions are allocated. In once case they are grandfathered (allocated at zero cost) and in the other they are auctioned (thereby raising revenue for the government). This distinction has important implications for the secondary or social costs of the policy that are manifest through interactions with pre-existing taxes, discussed in section IV H of the report.

The Tracking and Analysis Framework Model

Changes in emissions of relevant pollutants are fed into the Tracking and Analysis Framework (TAF). TAF is a nonproprietary and peer-reviewed model constructed with the *Analytica* modeling software.[3] TAF integrates pollutant transport and deposition (including formation of secondary particulates but excluding ozone), visibility effects, effects on recreational lake fishing through changes in soil and aquatic chemistry, human health effects, and valuation of benefits.

In this exercise, only changes in health status derived from increased particulates concentration are evaluated. These values are calculated at the state level and aggregated to the NERC region level; changes outside the US are not evaluated. Health effects are characterized as changes in health status predicted to result from changes in air pollution concentrations. Impacts

[3] *See* Bloyd et al., *Tracking and Analysis Framework (TAF) Model Documentation and User's Guide*, ANL/DIS/TM-36, Argonne National Laboratory (December, 1996). Each module of TAF was constructed and refined by a group of experts in that field, and draws primarily on peer reviewed literature to construct the integrated model. TAF is the work of a team of over 30 modelers and scientists from institutions around the country. As the framework integrating these literatures, TAF itself was subject to an extensive peer review in December 1995, which concluded that "TAF represent(s) a major advancement in our ability to perform integrated assessments" and that the model was ready for use by NAPAP (ORNL, 1995). The entire model is available at www.lumina.com\taflist.

are expressed as the number of days of acute morbidity effects of various types, the number of chronic disease cases, and the number of statistical lives lost to premature death. The health module is based on concentration-response (C-R) functions found in the peer-reviewed literature. The C-R functions are taken, for the most part, from articles reviewed in the US Environmental Protection Agency (EPA) Criteria Documents (for example, the so-called EPA Section 812 prospective and retrospective studies). The Health Effects Module contains C-R functions for PM_{10}, total suspended particulates (TSP), sulfur dioxide (SO_2), sulfates (SO_4), nitrogen dioxide (NO_2), and nitrates (NO_3). In this exercise, the potency of sulfates with respect to mortality effects is treated as distinct from the potency of nitrates. Sulfates are considered relatively more potent than other constituents of PM10, and nitrates are treated as comparable to other components of PM10. For morbidity, SO_2, PM_{10} and sulfate effects are aggregated according to a scheme designed to avoid double-counting, such as symptom days and restricted activity days. Alternatively, SO_4 effects can be used as a proxy for particulate and SO_2 effects. NO_x is included for eye irritation and phlegm days.

Inputs to the health effects module consist of changes in ambient concentrations of SO_2 and NO_x, demographic information on the population of interest, and miscellaneous additional information such as background PM_{10} levels for analysis of thresholds. The change in the annual number of impacts of each health endpoint is the output that is valued. The Health Valuation Submodule of TAF assigns monetary values taken from the environmental economics literature to the health effects estimates produced by the Health Effects Module. The benefits are totaled to obtain annual health benefits for each year modeled The numbers used to value these effects are similar to, though slightly lower than, those used in recent Regulatory Impact Analyses by the US EPA.