COMPETITIVE IMPLICATIONS OF ENVIRONMENTAL REGULATION IN THE ELECTRIC UTILITY INDUSTRY

by:

Donald A. Geffen, Ph. D. and Alfred A. Marcus, Ph. D.
Carson School of Management
University of Minnesota
Minneapolis, MN 55455

U.S. EPA Cooperative Agreement #CR824410-01

Project Officer:

Dr. Alan Carlin
Office of Policy, Planning and Evaluation
U.S. Environmental Protection Agency
Washington, D.C. 20460

Report prepared for:

Office of Policy, Planning and Evaluation
U.S. Environmental Protection Agency
Washington, D.C. 20460

The Management Institute for Environment & Business
June 1996

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INTRODUCTION

This study examines the response by the electric utility industry to the Clean Air Act Amendments of 1990, focusing primarily on the SO_2 provisions of the Act. It explores the competitive forces that developed among the providers of air pollution control technologies and the suppliers of low sulfur coal. It also explores competitive developments among the developers and vendors of natural gas turbine systems, the main clean alternative to coal for power generation presently available.

While often not fully recognized as such, this will be a story of highly successful pollution prevention: the reduction of pollution at the source by sharply reducing the sulfur contaminants in the fuel employed. At the nexus of this story is the electric utility industry, challenged both by deregulation and increasing competition and by new environmental constraints, and assisted by its key suppliers, competing not only among themselves in each sector but competing sector against sector to provide the best and lowest cost solutions to these challenges.

International markets and competition also played a role in this story. The major competitors for air control equipment and for gas turbine generating equipment were international companies. Markets abroad for both control systems and gas generating systems were strong and helped support the development and sale of new innovative products coming from these vendors.

INDUSTRY STRUCTURE

Product Description and Function

Electrical Energy

This ubiquitous but essential product in the past was almost totally taken for granted until there was a power failure. Taking electricity for granted was changing, however, with the advent of widespread use of computers and other complex electronic devices. Even a small variation in power output such as a small drop in voltage could disrupt these devices causing costly losses of time and valuable data and producing sudden production interruptions. As a result the electrical energy distributors were increasingly concerned with ensuring the quality as well as the reliability of their product.

Electric utilities transported energy in electromagnetic form over long distances from concentrated generating centers, where primary thermal energy was transformed into a more useful form. They also transported this energy locally among their customers. In 1993 56.9 percent of electrical energy came from burning coal and a much smaller percentage was generated by consuming natural gas[1].

[1] U.S. Department of Energy, *1993 Power Annual*

Bituminous and Sub-bituminous Coal for Electrical Power Generation

Coal was the mostly commonly used fuel in the U.S. for generating electricity. This fossil fuel had, by far, the most ample reserves in the world. There were two main types of coal.

Bituminous coal tended to be roughly 70 percent carbon and a few percent hydrogen which together represented the heating value of the mineral. The rest consisted of water, clays of various oxides (the unburned ash), oxygen, nitrogen, trace compounds (such as chlorine and calcium), very small amounts of metals (including mercury), and sulfur in various forms. The sulfur content could be as high as 6 percent by weight but grades of coal in use by generating facilities usually contained less than 4 percent sulfur. In 1993, total bituminous coal purchased by utilities averaged 1.71 percent sulfur, which at an average of 12,045 Btu / lb, corresponded to 1.42 pounds of sulfur per million Btu (MBtu) heat content.[2]

The sulfur content of the coal in Appalachian mines varied, and the proportion with less sulfur was uncertain and limited. The mines from which Appalachian (eastern) coal came were mature, fully exploited and had high extraction costs. Unlike natural gas (pure methane) and fuel oil (a refined hydrocarbon), coal had many properties with constituents of different concentrations depending on where it was mined and from which coal veins in the mine it originated.

Sub-bituminous coals were of lower quality than bituminous coals: compared with a pound of bituminous coal, a pound of western sub-bituminous coal supplied about 30 percent less heat. The moisture content of this coal tended to be much higher. Powder River Basin coal from Wyoming was about 30 percent water. However, its sulfur content was low. Sub-bituminous coals contained somewhat less ash than most bituminous coals but the experience of boiler operators was that it yielded troublesome amounts of difficult to control fine ash in the flue gas. In 1993, the average sulfur content of sub-bituminous coal sold to utilities was 0.41 percent and, with an average heat content of 8,763 Btu / lb, this equated to 0.47 lb / MBtu.[2]

Large reserves (30 years or more) of low sulfur coal were available in Western states in thick veins close to the surface. Even greater reserves existed somewhat deeper below the surface necessitating open pit mining to recover them, but at a cost still much below that in the East and Mid-West.[3] Low sulfur sub-bituminous western coal differed sufficiently from higher sulfur bituminous coals such that it usually could not be substituted for the latter in boilers without modifications.

Clean Coal Technologies

The following air pollutants, released when utilities burned fossil fuels, were regulated by the U.S. government: sulfur dioxide, nitrogen oxides, particulates from the ash, and several

2 U.S. Department of Energy, Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants 1993,* DOE / EIA-0191(93), July 1994. For a typical bituminous coal composition see, for example, "The Harrison Power Station," *McGraw-Hill's Power Magazine,* April 1994

3 U.S. Department of Energy, *Estimation of Coal Reserves by Coal Type, Heat, and Sulfur Content,* Energy Information Administration, DOE / EIA-0529, 1989

hazardous air pollutants (HAPs).[4] Emission standards for HAPs were under review and it was not clear to what extent utilities would have clean-up responsibilities. A variety of scrubbers to control SO_2 were on the market:[5]

Limestone Wet Flue Gas Desulfurization Systems (WFGD)

The most common form of flue gas desulfurization (FGD) equipment, it sprayed limestone slurry and water into the flue gas and formed a calcium sulfite and sulfate sludge that had to be disposed of in a landfill. These scrubbers usually removed 90 percent of the SO_2 from the flue gas; however, they could be enhanced to remove 95 percent and even as high as 98 percent at relatively low cost (an additional 5-10 percent in capital costs) with the addition of organic acid buffers. WFGD systems could be employed for a range of coal with different sulfur contents. They could be used for retrofitting existing units as well as in new facilities.

The capital costs of a system for a burner using 2 percent sulfur coal was about $30/kW less than for a burner using 4 percent sulfur coal. For the burner using 4 percent sulfur coal, the capital costs were approximately $120-150/kW for a new generating facility. Retrofitting tended to run 10-15 percent higher in capital costs. Some existing coal burning facilities had insufficient available space to install a WFGD system making more expensive modifications necessary.

In a variation on the WFGD, instead of sending the sludge to a landfill, the utility removed water and impurities from the sludge and made gypsum, a marketable product. According to GE Environmental Services, Inc. (GEESI), a major producer of WFGD systems, providing this capability added only $4/kW to the capital costs. However, adding it in the U.S. made sense only if a utility was located near an area of high demand for gypsum. Otherwise, the expense did not make it worthwhile. In Western Europe, on the other hand, the capability to convert scrubber sludge into a useful byproduct often was essential. Landfill permits to dump waste sludge were not easily available. In Germany, for example, a utility had to have this capability.

Labor and maintenance costs for WFGD systems were about 2.5-3.0 percent of capital cost per year. Parasitic power losses were about 1.5 percent of plant output and reagent prices were low, in the neighborhood of 0.05 /kWh, with limestone costing only $10/ton. A good estimate of the additional revenues needed to pay for WFGD systems was 0.4 /kWh, a cost greater than the added cost of fuel for burning natural gas in a combined cycle turbine generator in most parts of the U.S.[6]

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4 Carbon dioxide was an unregulated air pollutant of concern to the world because of climate change. It had been the subject of much discussion and a treaty at the 1992 Rio Conference.

5 Our discussion of scrubber technologies and markets relied greatly on marketing material of GE Environmental Services and on interviews of GE employees. For a discussion of the effects of the 1977 Clean Air Act Amendments on the scrubber market, see Bruce Ackerman and William Hassler, Clean Coal/Dirty Air (New Haven, Ct.: Yale University Press, 1981). In this book, the authors maintain that a coalition of eastern coal interests and environmentalists formed a coalition to strengthen the 1977 Clean Air Act Amendments in ways that would stimulate the market for scrubbers, though this solution was neither cost effective nor ultimately very good for the environment.

6 See Department of Energy, Electric Plant Costs and Power Production Expenses 1991, Energy Information Administration, 1993.

Dry FGD

This system sprayed an agent, usually lime in a slurry, and the agent then was vaporized by the flue gas. The waste product was dry and easier to handle. The SO_2 removal capability of this system, however, was about 70-90 percent. Thus, it was less suitable for facilities burning high sulfur coal and more so for facilities that burned low or medium sulfur coal. Capital costs were roughly 15 percent lower than for the wet flue gas systems. Sometimes, a baghouse could be used with higher sulfur coal to remove more of the sulfur dioxide.

Sorbent Injection Systems

Dry sorbent injection was cost effective for retrofitting older power plants where there was insufficient space to install more effective FGD systems at reasonable cost. Though more reactive sorbents could be used to enhance performance, and, in principal, these systems were capable of removal rates of up to 70 percent, in practice a 50 percent rate could be expected. Most injected a dry or slurry sorbent, commonly limestone, into the flue gas upstream of the particulate control system, but other injection systems had been developed that either injected limestone into the boiler (limestone injection multistage boiler or LIMB) or into the flue gas before the electrostatic precipitator (ESP). The Department of Energy (DOE) estimated that a B&W LIMB process system capable of removing up to 60 percent of the flue gas sulfur dioxide would have a capital cost of $30-100/kW.[7]

Natural Gas Turbines

Gas turbines (GTs) and combined cycle gas turbines (CCGTs) had outstanding environmental benefits: they emitted no SO_2, much less NO_x (as low as 25 parts per million without controls or less than 10 percent of the emissions limits for coal), and HAPs. Equally important, they had less neighborhood impact than coal fired units, (i.e., communities were less likely to protest the siting of an NG facility.)

Single Gas Turbine (GT) Units

This technology was a spin-off of the aircraft jet engine, modified for stationary power application and for burning natural gas. Units could use fuel oil (as jet engines did) or either natural gas (NG) or fuel oil. The models closest to jet engines ranged in power from 1/2 to 40 MW, while more advanced systems produced 150 to 250 MW of power. Their capital and fixed operating costs were half that of coal-fired systems. GTs attained thermal efficiencies of up to 40 percent and often were employed for cogeneration purposes.

Combined Cycle Gas Turbine Systems (CCGT)

These were mostly larger power systems that typically consisted of a GT (100 - 150 MW), a heat recovery steam generator (HRSG), and a steam turbine generator (50 - 100 MW). The gas turbine ran a separate electric generator. These systems typically were rated at about 250 MW

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[7] U.S. Department of Energy, Assistant Secretary for Fossil Fuels, *Clean Coal Technology Demonstration Program - Program Update 1993,* p ES-5, DOE/FE-0299P, March 1994

and attained thermal efficiencies of over 55 percent. Top of the line Asea Brown Boveri (ABB) and Westinghouse (WX) models reached 57-58 percent efficiencies while GE announced a new 60 percent thermally efficient model in 1995. Existing systems were priced at about $750/kW fully installed. Extremely stringent new source performance standards for NO_x could be met for an additional $50/kW capital cost. These systems also could be used in a cogeneration application.

Both GTs and CCGTs could be arrayed in modular units for additional power capacity. This feature was an important attraction for electric utilities and other power generators who preferred to respond to new capacity demands with an increment at a time so as to avoid the risk of having too much capacity (which could arise when large 500 MW or greater coal-fired plants were built). A 250 MW CCGT could be installed within two years or less. GT systems with low capital costs often were used to provide peaking power capacity for a few days a year. CCGTs had sufficiently high thermal efficiencies so that they were suitable for intermediate and base load applications.

Market Size

Electricity Markets

In 1993 a record 2.8 trillion kWh of electricity was generated in the United States, 1.6 trillion of which was fueled by coal and consumed 813.5 million tons of coal in the process.[8] Using Department of Energy (DOE) data, one could estimate an average thermal efficiency for coal generated plants of 33.6 percent. The demand for electricity in the U.S. was growing at a rate of about 2 percent per year. This growth rate was slower than real GDP growth due to conservation efforts (demand side management) which had more than counteracted the economy's increased use of electricity. However, diminishing returns from demand side management and a turnaround in U.S. manufacturing could yield acceleration in electricity use in the future.

Electric utilities until recently had monopolies in selling their products in their franchise areas. Deregulatory forces were changing their status and they increasingly looked to neighboring regions as sources of new markets and competition. Transmission losses and expenses, however, limited the distances from a utility's generating sources that it could serve to a few hundred miles.

Coal for Power Generation Market

Total coal deliveries to utilities were around 775 million tons per year, and they showed little growth. Imported coal accounted for less than 1 percent of the total BTUs delivered. Since coal consumption by electricity generators was 814 million tons in 1993, it suggested that inventories were low and that deliveries could be expected to increase somewhat. Deliveries of bituminous coal had shown very little growth from 1986-93, but deliveries of sub-

8 U.S. Department of Energy, *Electric Power Annual 1993*.

bituminous coal increased at a rate of more than 3 percent per year.[9] Utilities added very little net new coal fired capacity and had plans to add very little in the next few years.

The Market for Scrubbers

The world wide installed base of WFGD systems from 1981-1993 was 180,000 MW (or 180 GW). In the United States it was just under 63,000 MW. GE Environmental Services Inc. (GEESI) had a strong lead in this market with 26 percent of the world wide market share. The three countries with GEESI's largest installed base were the U.S. with 18,839 MW, Germany with 7,455 MW, and Japan with 5,925 MW. On a per capita basis, Germany installed proportionately far more systems than the U.S.

GEESI's WFGD marketing group projected a potential world wide market of over $7 billion for 1994-1997. In the U.S., it estimated retrofitting of 36,000 MW of coal fired plants for sales of $2.7 billion (averaging $75/kW) as a consequence of Phase II of the Clean Air Act (CAA). Under Phase I of this act, retrofits of 14,000 MW of electric power generation had occurred out of 65,000 MW of impacted capacity. With low cost alternatives to conventional WFGD systems such as clean coal and trading allowances available, most industry observers expected considerably less than 36,000 MW going the WFGD route. Sales of scrubbers in the U.S. in 1995 were very slow.

The international market was relatively healthy since Europe and Japan did not have the option of switching to low sulfur coal. Acid rain was having greater impact on European forests and lakes than in the United States. Poland, the Czech Republic, and Slovakia burned very dirty "brown" coal without adequate pollution controls. GEESI's projection of WFGD demand outside the U.S. was a more realistic $4.3 billion.

Gas Turbine Market

There was a definite trend away from coal and toward natural gas as an energy source in the U.S. As of 1990, there were 35 coal fired units (16.38 GW) scheduled to come on line over the next ten years, and 203 natural gas fired units (18.475 GW) scheduled. By 1993, the number of coal fired units scheduled had dropped to 16 (6.919 GW and an average of 432 MW per unit), while the number of gas fired units had increased to 278 (28.516 GW and an average of 103 MW per unit). These results have been summarized in Table 1.

[9] See footnote 2 and also the 1991 DOE report.

Table 1
Planned U.S. Plant Additions (in the next 10 years), by energy source and year

	New Units		New Megawatts (Generator Nameplate)	
	as of 1990	as of 1993	as of 1990	as of 1993
Total	421	480	48,189	44,502
Coal	35	16	16,380	6,919
Gas	203	278	18,475	28,516
% Coal	8.31%	3.33%	33.99%	15.55%
% Gas	48.22%	57.92%	38.34%	64.08%

(source: Inventory of Power Plants in the US: Energy Information Administration, 1990 Edition and 1993 Edition)

Independent power producers (IPPs) played an important role in the market share gain gas turbine generators achieved.[10] Lower capital costs, shorter construction times (often two years or less), easier siting and permitting, and simpler manufacturing of the modular gas units added to the low risk of employing this generating mode in comparison to coal. The long term problem with gas turbine generators was the availability and price of the fuel. However, expectations were for stable supply and prices for years to come.
It would be possible to estimate annual increases in electric power capacity in the U.S. by starting with the total generating capacity in place in 1995, roughly 500,000 MW (500 GW). With demand growing about 2 percent per year, one could expect annual capacity increases of 1-2 percent or 5 to 10 GW/yr. New capacity in 1994 was about 9.4 GW. Single gas-turbines were priced at about $190/kW -- not including installation and balance of plant. If 80 percent of new capacity additions were gas turbine based, many of these being CCGT, one could anticipate a U.S. market for gas turbine generators of about $1 billion per year.

Worldwide, the demand for new generating capacity was strong with various projections ranging from 629 GW to 820 GW installed during the period from 1994 to 2003.[11] A good part of that would be coal fired and nuclear, however. Siemens, a major international supplier of gas turbines and steam turbines, estimated that world wide demand would increase to a rate of 75 GW per year by 2000 of which about 28 GW per year would be gas turbine systems.[12] Gas turbine generator sales could amount to $4 billion annually.

10 A 1995 study, reported in the April 1995 issue of McGraw-Hill's Power Magazine, revealed that IPPs supplied over 57,000 MW of power to the U.S. power grid. They brought 91 projects on line totaling 5,735 MW (63 MW per project) in 1994. Most of the IPPs' projects were for gas turbine generators. According to the DOE's *1993 Electric Power Annual*, independent power generators produced 0.3252 trillion kWh in 1993, comprising about 12 percent of all electricity generated. Of this only 16 percent was by coal fired means. Assuming about 80 percent of IPP generation was by natural gas, close to 10 percent of all electricity generated in 1993 was supplied by independent power producers using, with few if any exceptions, gas turbine systems.

11 The McIlvaine Company, Northbrook, IL, *Gold Dust -- The "Air Pollution Management" Newsletter*, July 1995, No. 206.

12 The McIlvaine Company, Northbrook, IL, *Gold Dust -- The "Air Pollution Management" Newsletter*, July 1995, No. 206 .

Suppliers like GE and ABB reported good activity in the market for GTs both in the U.S. and abroad. However, price competition had become very prevalent. Siemens reported that power generation systems orders were down sharply for the June quarter of 1995.

THREAT OF NEW ENTRANTS

Electric Utility Industry

This industry faced the significant threat of new entrants. Deregulation was forcing growing competition in a heretofore sleepy regulated sector. Increasingly, utilities were filling new power generation needs by opening projects up for bids and treating their own power generation subsidiaries at arms length. In recent decades, construction delays and huge cost overruns had plagued many utilities and contributed to wide electricity price disparities in the U.S.

The burden of environmental regulations was being transferred to the IPPs that won bids, thus reducing the utilities' own risk. Utilities anticipated competition from utilities in adjoining areas and from IPPs that had lower cost power. All of the utilities were under pressure to reduce their own costs. This pressure affected their decision making with regard to SO_2 compliance, driving them to avoid anything but the lowest cost solutions.

Coal

No threat of new entrants existed here. The Powder River Basin, the dominant source for low sulfur sub-bituminous coal, was mined, under lease from the federal government, by 14 different companies including subsidiaries of five or six major oil companies.[13] Competition was strong and there was no visible new entrant on the horizon.

Scrubber Suppliers

The threat of new entrants was not a concern for several reasons: (i) the technology was becoming more advanced; (ii) quite a few companies had been in the business for some time and were well down the learning curve, so that the cost of entry was high; (iii) domestic demand was poor, discouraging new entrants into the U.S. from American and foreign companies alike; (iv) international demand was much better but the companies already in the industry had worldwide marketing and engineering capabilities that gave them a strong advantage; and (v) though the basic scrubber design was fixed, the final product had to be customized to each coal burning facility because of the great variability of these plants, so that only well established firms with good reputations could be trusted.

Gas Turbines

Though there was far less customizing, established international firms had a big edge. They had benefited from the learning curve for jet engine manufacture. Either they were a jet

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13 Dr. Robert L. Samsom, Energy Ventures Analysis, Inc., *Review of Powder River Basin Coal Supply*, June 1990 .

engine manufacturer themselves (GE) or they had formed close ties with other jet engine manufacturers, such as Pratt and Whitney. All of the existing companies had these relationships. Competition was fierce and a new advanced product appeared every two years. Barriers to entry were formidable.

LEADING SUPPLYING NATIONS

For scrubbers, United States companies had the lead followed by Switzerland, Germany, and Japan. In gas turbines, the U.S. led but was in close competition with Switzerland and Germany. For sulfur dioxide scrubbing and gas turbine equipment, the major competitors were multinational corporations like GE, Siemens, ABB, and Westinghouse (WX) whose home base was secondary to their international presence.

COMPETING FIRMS

General Electric

GE was one of the largest and most diversified companies in the world with 1994 total revenues of $39.6 billion. Excluding GE Capital, one of the largest commercial lending and leasing companies, GE's Power Generation division, primarily gas and steam turbine generators, comprised 15 percent of revenues or $5.9 billion, and its related Aircraft Engine division 14 percent. In the U.S., GE's market share of gas turbine generators from 1990-95 had been as high as 80 percent. It achieved this dominance by being the first company to introduce a combined cycle gas turbine (CCGT) with thermal efficiencies of 55 percent (its F technology).[14] Most of its competitors ultimately caught up bringing GE's market share down to about 50 percent in 1995. The four major competitors could offer CCGT systems in the 57-58 percent efficiency range in 1995. GE's announced its G series in 1995 reaching CCGT efficiency of 60 percent. This product had the potential to increase its market share again. GE also commanded a leading place in the international market with about a 50 percent share. It accomplished this lead by having many partners who were non-U.S. manufacturers and packagers that used GE components. Twenty percent of GE's international sales were by direct export.

The remaining market shares in the United States and world wide were divided up among ABB, WX, and Siemens with ABB in second place world wide and WX and Siemens tied for third place. In the U.S., WX and ABB had about 20 percent each of the gas turbine market and Siemens about 10 percent. Siemens won a number of important U.S. contracts in 1995. Most producers had to slash prices to get orders. The industry suffered from over-capacity and its growth was not as large as expected. Siemens and ABB did not have flexible labor forces, and they had to preserve market share to maintain employment.

Earnings and cash flow for GE expanded consistently from 1985-95 at rates of 11 and 9 percent respectively on revenue growth of only 4 percent per year. Revenue growth was accelerating

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14 Private communication. The gas turbine market share information was obtained from an interview of a GE employee. Much of the information contained in this section is widely available in the financial analysis literature.

with the revival in industrial sector demand. However, power generation profits were under pressure despite strong revenue growth because of the pricing issue referred to earlier.

Westinghouse Electric (WX)

WX also was a diversified company but much smaller and far less successful than GE. Its financial services division, which had been discontinued, was beset with bad loans that put the company under stress and near bankruptcy. The stock price had fallen from a high of 39 3/8 in 1990 to lows of 9 1/2 in 1992 and 10 7/8 in 1994. In 1995, it rebounded to 15 with attention focused on the acquisition of CBS. Total revenues in 1994 were $8.85 billion. Broadcasting revenues comprised only 10 percent of these revenues, but contributed 33 percent of operating earnings.[15] Profitability was being dragged down by WX's Energy Systems division, which serviced the nuclear power markets. It had 14 percent of revenues but only 1 percent of operating earnings. A small furniture subsidiary had 6 percent of sales and losses totaling 11 percent of operating earnings.

In this context, Westinghouse's Power Generation division was doing comparatively well with 19 percent of sales (or $1.7 billion) and 15 percent of operating earnings. Power Generation's margins, close to 8.6 percent, however, were less than the company's overall operating margins of 11 percent.

Earnings and cash flow had been dropping since 1990 and Power Generation was having margin pressures despite rising sales due to price competition overseas and a poor U.S. service market. WX had advertised "The World's Largest And Efficient 60 Hz Industrial Gas Turbine," the 501G, with an output of 230 MW (single turbine), 38.5 percent thermal efficiency, and producing (when in tandem with a steam generator and HRSG) the highest efficiency in the industry of about 58 percent. However, GE's G turbine, which it announced in 1995, would be able to surpass this level of efficiency.

Asea Brown Boveri Ltd. (ABB)

ASEA, a Swedish company and a long time leader in utility, electrical equipment, and electric-rail equipment, merged with BBC Brown Boveri Ltd. of Switzerland in 1988. 1994 total sales were $29.7 billion of which $15.7 billion were manufactured products for the generation, transmission, and distribution of electric power, which made it the world's largest manufacturer of electrical energy related equipment. ABB had purchased Westinghouse's transmission and distribution business and the U.S. engineering firm of Combustion Engineering. The remainder of ABB's revenues were related to the sale of environmental controls, mass transit systems, and industrial equipment. Headquarters were in Zurich. The company's Industrial and Building Systems division provided capital improvements for industries such as pulp\paper and steel and drilling equipment for oil exploration.[16]

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15 Other profitable segments included the ThermoKing transportation refrigeration service with 10 percent of sales and 21 percent of operating earnings, Electronic Systems (primarily defense contracting) with 28 percent of sales and 27 percent of operating profits, Environmental Systems (hazardous and nuclear waste cleanup) with 4 percent of sales and 9 percent of operating earnings, and Communities (land development) with 3 percent of sales but 11 percent of operating earnings.

16 ABB was waiting approval to merge its Transportation segment with Daimler Benz's rail business for further economies

Growth since 1990 had been negligible. Earnings fluctuated but cash flow and sales were fairly constant in the 1990-95 time period. ABB's stagnation was not surprising given the worldwide slump in the industrial capital equipment sector in many parts of the world. ABB, however, did appear to be breaking out into a period of growth starting in 1995 with the revival of industrial investment and strong demand for infrastructure in Asia. ABB's gas turbine sales world wide, based on its 20 percent share, and including steam generators, was about $2.4 billion in 1994. Its most advanced CCGT boasted an efficiency of 57-58 percent just behind Westinghouse.

Siemens

This well known German company was a leader in a range of technologies for electrical engineering and electronics systems. Its products included systems and services for telecommunications, electric power generation and distribution, factory automation, electric-rail systems, automotive electronics and other electronic and semiconductor components, computers, and medical engineering. Total sales in 1994 were $51.1 billion which made it the largest of the four gas turbine competitors considered here. This was somewhat misleading, however, since GE's very large and important financial services subsidiary did not add to GE's revenue figure. In 1994 GE's cash flow was exactly twice Siemens' cash flow of $3.76 billion dollars. Siemens, essentially a pure industrial company, was simply larger than GE industrial.

Like ABB, Siemens had a difficult 1994 due to the economic slowdown in Europe where its sales were the strongest. Sales to the more vibrant Asia Pacific were only a small part of the company's revenues. Sales of the Energy Systems division in 1994 were about 16 percent of total sales or about $8 billion dollars. June quarter 1995 results showed a slowing in its power generation business. Although sales continued to climb in this year over the prior year -- up 6 percent, orders dropped 29 percent to $3.4 billion. In June 1994, orders had been $4.9 billion.

GE Environmental Services Inc. (GEESI) and Competitors

This subsidiary of GE was part of its Industrial & Power Systems division. It was formed in 1981 when GE acquired two separate divisions from two engineering firms. It had a strong portfolio of air pollution control devices and its association with GE Power gave it ready access to its markets. GEESI was a world-wide market leader in WFGD systems with 26 percent of the installed base from 1981-1993.[17] Its major competitors were ABB at 13 percent and Babcock & Wilcox (B&W), a subsidiary of McDermott International, with 12 percent of the world market. In the U.S., GEESI shared market share leadership with ABB and B&W with 30 percent each of the 1981-1993 installed base. ABB's strength in the U.S. was due to its acquisition of Combustion Engineering. These three closely competing companies had 90 percent of the U.S. market. Mitsubishi Heavy Industries had managed to garner 6 percent of both world wide and U.S. market share. Deutch-Babcock had 9 percent of the market outside the U.S., but only a 1.5 percent U.S. market share. ABB's and B&W's world wide market share

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of scale and to take leading market share in what has been a three way race with Siemens and Alcatel.

17 Private communication. Much of the information about this industry came from an interview of GEESI staff and their marketing material.

were 9 and 8 percent. GEESI was successful in international markets because of its partnerships with licensees in Europe, India, Southeast Asia, Japan, and Korea.

COMPETING TECHNOLOGIES

No power generating technology threatened to displace the gas turbine as the low cost environmentally friendly alternative to coal fired systems. Fuel cells had an even lower environmental impact than gas turbine technology and they were far quieter. They promised to offer high thermal efficiencies comparable to the best that CCGT had to offer and with better performance at lower output levels and for small (several MW or less) units suitable for commercial, industrial, and institutional sites. Costs, though, still were very high, so that fuel cells did not look as if they would be competitive for at least five years or longer.

GE Environmental Services Inc. had developed an ammonia reagent WFGD system which used most of the components of the limestone WFGD, but replaced the limestone with ammonia, and yielded a byproduct of granulated ammonium sulfate, a high value added fertilizer. GE had a proprietary patented process that the company expected would give it the entire market for this application for years to come. The capital cost was 30 percent greater than for a limestone/gypsum WFGD and the SO_2 removing capabilities were similar to the latter's. The additional cost was for capability to treat the ammonium sulfate sludge to make it marketable. Unlike gypsum byproduct, which was low priced and whose sale did not provide a positive cash flow, granulated ammonium sulfate sold for a high price and could yield positive cash flows.

The first installation of this system was coming on line in North Dakota in 1996. The cost profile looked very favorable provided a growing market for the byproduct developed. Although this technology, if it performed as GEESI claimed, could increase the company's market share, it would not have major impact unless an expanded market could be found for its byproduct, the granulated ammonium sulfate fertilizer. One other difficulty was that utilities did not want to enter the fertilizer production business in which they had no experience and which was subject to volatile pricing. Nevertheless, this system bore watching as it was the only new technology that could challenge conventional systems at a lower cost. World-wide demand for the new, lower cost ammonium sulfate scrubber (when the facility is near a market for the byproduct) could conceivably reach $750 million to $1.5 billion over the next five years displacing 10 to 20 percent of the current higher cost suppliers of ammonium sulfate fertilizer.[18]

Other air pollution control devices, that could remove substantial percentages of SO_2, NO_x, and many HAPs, were in the testing and development stages; for example, the Mitsui -- Bergbau Forschung (BF) activated coke process that had been installed at facilities in Japan and Germany. This type of product could become a significant factor in the U.S. if HAP and NO_x standards were tightened to the levels found in Germany and Japan (see later discussion).

18 Private communication

ENVIRONMENTAL, HEALTH AND SAFETY PRESSURES

The Acid Rain Problem and the 1990 CAA

The 1970 Clean Air Act Amendments (CAAA) authorized the EPA to set ambient standards for SO_2 to protect health and prevent damage to materials. It applied to concentrations at ground level and did not prevent sources from building high stacks and transporting emissions to other areas and states. In 1990, after a decade of debate, Congress and the administration tackled the "acid rain" problem from coal fired power plants and passed additional amendments to the Clean Air Act. Acid rain, formed primarily when sulfur oxides and to a lesser extent nitrogen oxides precipitate out of the atmosphere, had damaged many forests and lakes. A major culprit was the high-sulfur coal used by electric utilities and the nitrogen oxides, or NO_x, that were formed as a consequence of the combustion process. According to the EPA's 1989 emissions inventory[19], utilities were responsible for 69.4 percent of U.S. SO_2 emissions and 32.4 percent of total NO_x emissions.

Implementation of sulfur dioxide emission reductions was to be achieved in two phases.[20] The first phase affected 260 units with power ratings of 100 MW or greater situated at 110 power plants in 21 states. These units, owned by 55 electric utility organizations, comprised about 13 percent of total U.S. electric generating capacity. They were chosen by virtue of their emitting SO_2 at an average annual rate of over 2.5 lb per MBtu of coal consumed and they were required to cut sulfur dioxide emissions by January 1, 1995 to 2.5 lb/MBtu or less. Two-year extensions could be given to plants that committed to buy scrubbing devices that allowed continued use of high-sulfur coal. Utilities would have to cut nitrogen oxide emissions as well, beginning in 1995. Except for areas heavily impacted by smog, or other local situations that prompted stricter controls, these NO_x restrictions were expected to be met by installing low NO_x burners[21] at a relatively low cost. Local ambient air standards could result in lowered emission requirements for SO_2 necessitating the use of scrubbers.

The 1990 Clean Air Act Amendments also included an innovative pollution-trading system.[22] Under Phase I, generators were given enough allowances (1 ton of SO_2 per allowance) for them to emit the maximum allowed 2.5 lb/MBtu. The total number of allowances granted to a facility was based on its average annual number of BTUs of coal consumed during the 1985-1987 period. On January 1, 1995, generators were required to return to the EPA the number of allowances that corresponded to their actual emissions. They could retain any that remained should they be emitting below the limit of 2.5 lb/MBtu. This plan offered electricity generators that cut their emissions by more than the required amount the option to sell their "unused" pollution rights to other utilities whose cost of SO_2 emission reduction was higher than the price of the allowances. Utilities might also have chosen to keep the allowance for their own future use should they need to expand capacity. Units that cut emissions by

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[19] U.S. Environmental Protection Agency, *The NAPAP Emissions Inventory (Version 2)*, November 1989

[20] See for example, U.S. EPA Publications: EPA430/F-92/016 & 019, December 1992 for a discussion of this program.

[21] U.S. EPA Acid Rain Nitrogen Oxides Emission Reduction Rule 40 CFR Part 76 of Title IV of the 1990 Clean Air Act Amendments and modified by 60 FR 18751 after the *Alabama Power Co. v. EPA*, 40 F.3d 450, 39 ERC 1737, November 29, 1994 decision of the U.S. Court of Appeals for the District of Columbia Circuit.

[22] U.S. EPA Publication EPA430/F-92/019, December 1992

reducing output as a result of energy conservation efforts were also able to earn allowances. Bonus credits were awarded to dirty utilities that installed scrubbers, to power plants in high-growth and extremely low-polluting states, and to utilities that had already reduced their emissions before the CAA Amendments took effect. A similar procedure was in place for the lower limits required in Phase II.

In Phase II, beginning January 1, 2000, more than 1900 additional units rated at 25 MW or greater as well as the Phase I affected plants would have to make sulfur-dioxide cuts to attain emission levels of no greater than 1.2 lb/MBtu. This deadline could be extended until 2004 for plants that used new clean-coal technology. In addition, allowances would be used so that a fixed cap on emissions of 8.95 million tons of SO_2 per year would be in force. New capacity would not be issued allowances but instead had to obtain them from existing holders. To put this cap in perspective, the DOE indicated[23] that total power plant SO_2 emissions in 1993 were 14.4 million tons leaving a required reduction of about 5.4 million tons. The DOE further reported that SO_2 emissions dropped by 1.3 million tons from 1989 through 1993. With current SO_2 Allowance prices near $130/ton of SO_2 removed, eliminating 5.4 million tons represented an allowance purchase cost of $702M. New coal burning facilities would be even further limited because of the provisions of the 1970 and 1977 CAA Amendments pertaining to setting "New Source Performance Standards."

New Source Performance Standards (NSPS)

The rules were very complex and applied on a case by case basis. The 1977 Amendments empowered the EPA to set NSPS for factories and plants built after the Act's passage. In 1971 the EPA set the standard at no more than 1.2 lb. of SO_2 per MBtu. This strongly encouraged utilities constructing a new coal-fired generating plant to design it for low sulfur coal with sulfur content $\leq$ 0.6 lb/MBtu. This was a very favorable development for Powder River Basin coal producers. Both environmental advocacy groups and high sulfur coal producers were unhappy with this provision and managed to convince Congress to attach language to the 1977 CAAA that prescribed the use of scrubbers as a part of the NSPS. A sliding scale was put in place so that the plants using the highest sulfur coal would have to install scrubbers capable of 90 percent SO_2 removal rates to 70 percent removal rates for low sulfur coal users. Although systems with 70 percent absorption rates are less costly than those with 90 percent absorption rates, this provision dampened the utilities' enthusiasm for low sulfur (western) coal. These standards clearly gave an impetus to the move by generators toward natural gas turbine generators.

Existing plants that underwent modifications (improvements in boiler efficiency for example) also might face re-permitting requirements and come under the stricter provisions of the new source performance standards. In this way, NSPS had the tendency to inhibit older coal plant operators from improving their facilities.

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23 U.S. Department of Energy, *Electric Power Annual 1993*

International SO_2 Regulations

Acid rain provisions around the world varied.[24] They were negligible in China and very strict in Sweden, Germany, and Japan. Regulations, such as in the former Soviet Republics or in Mexico, were quite severe by law but not effectively enforced. There was more incentive abroad than in the U.S. to construct flue gas desulfurization systems. Plans to use FGD systems were strong in Asia. For instance, South Korea's 1995 SO_2 emission standard was 1.2 lb/MBtu, the level the U.S. required only by the year 2000. By 1999, South Korean facilities would have to reach an emission level of no more than 0.6 lb/MBtu. While low sulfur coal could meet the 1995 standard (and apparently South Korea has been using such coal) it could not attain the 0.6 lb/MBtu standard without FGD devices. Consequently, limestone/gypsum WFGD systems were being installed at a 2000 MW station in that country and bids were being prepared for 16 500 MW FGD systems. Furthermore, by 2006, 27 new coal-fired plants, totaling 14 GW of capacity were scheduled to be built and all of these would have to have some type of FGD system.[25]

Other Government Interaction

The DOE was involved in a "Clean Coal Technology" program to develop better, lower cost pollution control technologies for coal-fired generating plants. About $7 billion had been spent[26] (34 percent from the federal government, 3 percent from state agencies, 51 percent from power generators, and the remainder from the private industry participants). Over $4.7 billion of this money was devoted to advanced electric power generation technologies such as fluidized bed and integrated coal gasification projects. Another $687 million was allocated for developing environmental control devices including several inexpensive low NO_x burner systems and lower cost 50-60 percent SO_2 removal systems applicable for retrofitting older boilers. Several advanced WFGD systems were part of the program as well. B&W, ABB, Pure Air On the Lake, L.P. (a limited partnership jointly owned by Air Products and Chemicals and Mitsubishi Heavy Industries), and AirPol participated with SO_2 control projects. GE Environmental Services, Inc. did not participate.

INNOVATION IN RESPONSE TO ENVIRONMENTAL PRESSURES

The Natural Gas Turbine

Natural gas turbine (GT) and combined cycle gas turbine (CCGT) electric power generating systems had experienced dramatic technological and cost improvements driven, at first, by non-environmental forces, but more recently by environmentally friendly features as well as technical and economic benefits.

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24 Carbon taxes were seriously discussed in the European Community, but had not been implemented because of concerns they would put European manufacturers at a competitive disadvantage globally. The German, Dutch, and other governments in Northern and Western Europe were strong supporters of carbon taxes.

25 The McIlvaine Company, Northbrook, IL, *Gold Dust -- The "Air Pollution Management" Newsletter,* July 1995, No. 206

26 U.S. Department of Energy, Assistant Secretary for Fossil Energy, *Clean Coal Technology Demonstration Program, Program Update 1993,* DOE/FE-0299P, March 1994. The spending figures and other descriptions of the program were taken from this publication.

Two important but independent technological developments, not environmentally driven, came together to open the market for gas turbine generating systems:

(i) The costs of finding natural gas fell dramatically due to high performance PCs and work stations capable of processing 3D seismic data and due to advanced drilling technologies such as horizontal drilling systems. These technologies were a byproduct of the need to find petroleum more cheaply and of the explosive innovations in microprocessors and memory devices.

(ii) Constant technological advances in jet engine design and manufacture, fostered by a high level of both military spending and spending for commercial aircraft, enabled these engines to be successfully adapted for electric power generation.

Environmental pressures also contributed to these advances. Natural gas, recognized as a "clean" fuel was regarded as being even more attractive after passage of the 1990 CAA. There were no SO_x emissions to control. NO_x emissions, even without controls, were considerably below that coming from coal-fired boilers. HAP emissions were less and mercury and other heavy metals were not present. The CAA focused the natural gas industry on competing for the new power generation market. It contributed to directing increased resources to finding and developing natural gas reserves in response to the expected growth in demand. It also played a role in the increased investment in gas turbine technology development and the rapid technological advance.

In both natural gas exploration and gas turbine technologies, the innovations came from incremental steps nurtured and facilitated by countless innovations in other areas ranging from better materials to computer aided design and analysis.

After the passage of the 1990 CAA Amendments, the four fiercely competitive major manufacturers, led by GE, drove the thermal efficiency of combined cycle gas turbine generators (CCGT) from under 55 percent to the 60 percent achieved by GE's 1995 announced G series model. Because coal-fired systems have much lower efficiencies, a 60 percent efficient CCGT has equal fuel operating costs at a natural gas price of 1.8 times the price of coal. With low sulfur western coal priced in 1995 near $1/MBtu and natural gas delivered price to large industrial or utility customers in many parts of the country in the neighborhood of $2.00/MBtu, the fuel operating cost difference between advanced CCGT and coal systems became small. Of significance was the fact that 1995 natural gas discovery costs had fallen to about $1.70-1.80/MBtu. With the capital costs for NG fired plants being much lower than coal fired plants, NG plants had clear advantages over coal.

Low Sulfur Coal from the West

The Powder River Basin in Wyoming and to a lesser extent Montana, had large reserves of low sulfur coal (mostly ranging from 0.25 lb/ MBtu to 0.60 lb/MBtu) contained in thick veins lying close to the surface.[27] Serious development of the mines began with the passage of the

[27] U.S. Department of Energy, Energy Information Administration, *Estimation of Coal Reserves by Coal Type, Heat, and Sulfur*

CAA in 1970. The 1971 version of new source performance standards created demand for low sulfur coal. The oil supply crises of the 70s and skyrocketing energy prices inspired investment. The 1980s saw substantial advances by the mining companies[28] in improving productivity with larger more efficient earth movers, trucks, and other equipment. As a result, 1995 operating costs were estimated to be $3-4/ton or about 14-23 /MBtu. A miner in Wyoming and Montana produced over 20 tons of coal in an hour, in contrast to Appalachia where an hour's labor brought in only 3 tons of coal.
Western coal was selling for about $1/MBtu delivered to utilities in such states as Nebraska, Iowa, Kansas, Minnesota, and Wisconsin (spot prices as low as $0.80/MBtu existed). A large fraction of the delivered cost of Powder River Basin low sulfur coal was the cost of transportation. Burlington Northern (BN) led the way in developing rail transportation from the Powder River Basin. During the 70s, tracks to the many mines had to be laid and, while the Chicago & Northwestern (C&NW) jointly owned the rights of way, it was BN which had the initial capital to lay the tracks.[29]

Burlington Northern began delivering coal to utilities first and enjoyed several years of monopoly and high rates until the ICC stepped in after protests from BN's customers.[30] Chicago and Northwestern (C&NW) joined with Union Pacific (which now owns C&NW) to offer competing service in mid 1984. Competition was unleashed, rates dropped, and the rails entered the long struggle to cut operating costs and improve efficiency.

The railroads engaged in an ongoing process of improving operating efficiency bringing together technology advances from many sectors: computers and automation for better scheduling and traffic controls (a major problem given the enormous volume of traffic involved), electric and diesel motor technologies for more powerful locomotives at lower cost (here GM and GE were in strong competition), better coal hoppers, and better tracks. The end result was that the transportation costs to deliver a ton of Powder River Coal to distant utility markets was lower than it was before 1984 and comparable to prices in 1984 before C&NW entered the market. In current dollars prices were down over 40 percent in real terms since 1984.[31]

The continued growth prospects the railroads saw for western coal hauling continued to spur technological improvements. A new, more powerful locomotive introducing AC electric traction motors promised to lower operating costs.[32] Burlington Northern designers and engineers designed a "Trough Train" composed of extended cars of 13 articulated sections that

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Content, DOE/EIA-0529, 1989; Dr. Robert L. Samsom, Energy Ventures Analysis, Inc., *Review of Powder River Basin Coal Supply,* June 1990

28 Private communications

29 For a good account of the development of rail transportation out of the Powder River Basin see Fred W. Bailey and Gary J Benson, *Trains, The Magazine of Railroading,* Kalmbach Publishing Co., November 1989.

30 See Forest Reinhardt, "Acid Rain:Burlington Northern, Inc. (A)," Harvard Business School, case 792- 018, 1991.

31 For example, PSI Energy's Gibson Station in Indiana purchased coal with a sulfur content of 0.43 lb/MBtu from Powder River Basin for $1.21/MBtu delivered in 1993 and 0.75 lb/MBtu sulfur coal from nearby Kentucky for $1.37/MBtu. This low sulfur coal was not typical of coal coming from Kentucky: all Indiana utilities combined purchased Kentucky coal averaging 2.59 lb sulfur/MBtu at an average price of $1.16/MBtu, only five cents below the price of Wyoming coal. Since 1993 the price of Powder River Basin Coal fell substantially.

32 Interview of Gerald Grinstein, C.E.O. of Burlington Northern Inc., by *Siemens Review,* May 1993, reprint courtesy of Burlington Northern.

increased the coal carrying capacity of a unit train by 30-40 percent. The doors were completely redone for easier unloading and the new more aerodynamic exterior reduced wind resistance. Lighter car bodies made of aluminum replaced steel to further improve the efficiency of the coal delivery system.[33] BN's vision of the future was to develop the low-sulfur Powder River Basin coal market in the Eastern U.S., Canada, the Pacific Rim, Europe, Mexico, and beyond. Thus, it needed to drive prices down still further. As Table 2 below shows, this vision was close to becoming a reality.

Table 2

Average 1993 Coal Prices and Sulfur Content Per Million BTUs Delivered to Outlying States From Powder River Basin, Wyoming Compared With the Averages From All Coal Sources to That State

Receiving State	Wyoming Coal Delivered Price ($/MBtu)	Wyoming Coal Sulfur Con-tent (lb/MBtu)	Avg. Price All Coal Delivered ($/MBtu)	Avg. Sulfur Content All Coal (lb/MBtu)
Arkansas	1.70	0.38	1.70	0.38
Georgia	1.45	0.37	1.78	1.14
Indiana	1.20	0.39	1.27	1.61
Kentucky	1.22	0.59	1.17	2.09
Louisiana	1.63	0.52	1.59	0.66
Massachusetts	1.75	0.34	1.68	0.80
Michigan	1.09	0.33	1.53	0.59
Texas	1.67	0.40	1.44	1.15

(source: U.S. Department of Energy, Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants 1993)*

Sulfur dioxide scrubbers

The scrubber industry took two approaches to competing with low sulfur coal and gas turbine generators: (i) reducing the costs of limestone WFGD systems; and (ii) seeking alternative scrubbing technologies. From 1985-95, conventional limestone WFGD systems came down in real price as overall costs stayed roughly constant in current dollars.[34] Though it was a substantial reduction in cost, it was not enough for WFGD systems to be competitive with the fuel switching option at many utilities. Technological development centered on speeding up the limestone feeding system, thereby enabling designers to reduce the size of the unit and hence its cost. Overall advances were spurred by sales opportunities abroad and stiff competition for these opportunities.

An alternative approach was to take advantage of stricter NO_x emission standards and coming HAP emission requirements and develop an all-in-one system to reduce the cost

33 Burlington Northern brochure, 1992

34 Private communication, General Electric Environmental Services Inc. (GEESI)

compared to separate units to solve each problem. All the major competing air pollution control companies had combination (SOX-NOX) scrubbing systems.

Babcock and Wilcox had a "SO_x-NO_x-Rox Box" removing 80-90 percent SO_2, 90 percent NO_x, and 99 percent particulates (Rox). According to the DOE[35], the capital cost was estimated at $260/kW for a 250 MW plant which was comparable to the sum of the cost for scrubbers, NO_x control systems and particulate capture devices such as electrostatic precipitators (ESP) or baghouses. This capital cost was high and while the NO_x removal rate was excellent the SO_2 removal rate could have been higher. The DOE report cited the "potential for lower capital and operating costs and smaller space requirements than for a combination of control technologies." The system was operating successfully at an Ohio Edison plant in Dilles Bottom.

ABB Environmental Systems had a SNOX™ technology that was also being tested at an Ohio Edison facility, this one at Niles Station. According to the DOE, "The utility is making the technology a key part of its 1990 CAA compliance strategy."[36] The SNOX system was achieving 94 percent removal rates for NO_x and 96 percent SO_2 absorption resulting in marketable sulfuric acid as the byproduct. No solid waste was produced. No cost figures were available. ABB's approach combined the strategy of a marketable, more valuable byproduct and a combined removal system. Neither ABB nor B&W had attacked the problem of HAP emission controls. Both of the above systems were developed with the help of DOE funding under the Clean Coal Technology program.

GEESI licensed to develop a system by Bergbau Forschung and for Japanese markets by Mitsui Mining (see earlier mention of this technology). GEESI planned to adapt the system for North American markets. The system used activated coke produced by Mitsui, which was much cheaper than activated carbon. The system had been tested in plants in Germany and Japan and was capable of very high (>98 percent) SO_2 removal rates, 70-90 percent NO_x removal, >90 percent flyash capture, and high removal rates for several air toxics (including 99 percent mercury capture). It produced either sulfur or sulfuric acid as a marketable byproduct. The system did not seem to be able to handle the higher inlet concentrations associated with burning high sulfur coal. The capital costs, still uncertain, were estimated to range from $80-190/kW. This system could be a competitive offering with the coming of HAP and new source performance standards.

INNOVATIVE FIRMS

The customers for these technologies were in the electric utility industry.[37] This industry was undergoing dramatic change driven by industrial customers in search of lower costs and by state and federal regulators slowly moving towards increased deregulation and competition. Most utilities charged their captive industrial customers an electricity price that was higher

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35 U.S. Department of Energy, Assistant Secretary for Fossil Energy, *The Clean Coal Technology Program -- Lessons Learned,* DOE/FE-031P, July 1994; *Clean Coal Technology Demonstration Program, Program Update 1993,* DOE/FE-0299P, March 1994

36 U.S. Department of Energy, Assistant Secretary for Fossil Energy, *The Clean Coal Technology Program -- Lessons Learned,* DOE/FE 031P, July 1994

37 See Carol Sanchez, Environmental Regulatory Impact and Firm Level Innovation: A Study of Electric Utilities' Responses to the Clean Air Act Amendments of 1990 (PH.D dissertation, Department of Management, SIU, 1995).

than the marginal cost. Neighboring utilities often had different prices for their electricity, a disparity that could arise from a variety of causes.[38] Large consumers of electric energy saw nearby utilities offering power at lower rates than their own utility did and pressed regulators to permit "retail wheeling." They sought to require the local utility to transmit the power of another utility to supply them with electricity. Regulators were reluctant to do so for fear that higher cost utilities would be forced to write off inefficient plants. Most utilities, however, expected some degree of retail wheeling to evolve and were planning for it.

These new competitive forces in the electric utility industry were the result of similar forces in the global economy. Manufacturers were in a position where cost increases could not be easily passed on to customers. They had to cut costs to maintain profitability and market share. Inject the 1990 Clean Air Act Amendments and the utility industry, beset by cost conscious customer, had to absorb costs that could not be passed-on. The result was the utilities' relentless search for lowest cost solutions to problems posed by CAA compliance.

The utilities faced two challenges:

(i) how to comply with Phase I and II of this act?
(ii) how to meet new generation capacity needs given NSPS?

To illustrate how they faced these challenges let us take the example of a group of utilities located in a region that sweeps an arc from the Southeast into Texas. These utilities were all large and in an area of the country with above average growth in the demand for electricity because of its vibrant economy and expanding population. In the case of augmented competition and advancing deregulation, they would become competitors for some of the same industrial customers. Together they generated 22 percent of all power in the U.S.

Below in parentheses were the average prices in /kWh that they charged their industrial customers in 1994, the population served in millions, and the percentage of capacity provided by their coal-fired facilities.[39]

- Baltimore Gas and Electric (4.64 /kWh, 2.6M, 44% coal)
- Dominion Resources (Virginia Power) (4.33 /kWh, 1.8M, 39% coal)

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38 The lower priced utility may have managed its fuel sources better and its portfolio of fuel-based generating capacity. Its labor costs may be lower either through better management or having a lower wage scale in its region, and its operating and maintenance costs may be under better control. The higher cost utility may have had a badly managed new capacity addition over the past twenty years whose large cost overruns have been partially passed along to consumers. A manufacturer in New York paying 6 /kWh, sees a competitor in the Mid-West paying only 4 /kWh and contemplates three options: (i) move the facility to a lower cost state, (ii) generate the electricity on-site, if possible using the waste heat for process heat, or (iii) negotiate with the utility for lower rates. Increasingly industrial customers are combining options (ii) and (iii) by presenting the utility with a credible plan to build on-site generation unless rates are lowered to meet the cost of power the on-site facility will provide. In Minnesota where the price of electric energy is relatively low, several customers of Northern States Power (NSP) have done just that and have obtained a significant lowering in their price of power down to the 3 /kWh area. This agreement is for five years after which time NSP is willing (unless conditions change, of course) to let these customers leave the grid and generate their own power. NSP has also re negotiated rates with a large customer who threatened to leave the state unless his/her conditions were met. These examples are being repeated all over the U.S. and are most frequent in high cost areas.

39 Data comes from the companies' 1994 10K reports and the financial analysis literature (in particular work done at Prudential Securities and Merril Lynch); also see Department of Energy, Financial Statistics of Major U.S. Investor-Owned Electric Utilities 1993, Energy Information Administration, 1995.

- Duke Power (4.24 /kWh, 4.9M, 43% coal)
- Carolina Power and Light (5.29 /kWh, 3.5M, 60% coal)
- Southern Company (Georgia Power, Alabama Power, Mississippi Power, etc.) (3.70-4.52 with a system wide average of 4.30 /kWh, 11M, 73% coal)
- Florida Power and Light (FPL Group) (4.91 /kWh, 6.5M, 6% coal)
- Florida Progress Company (FPC) (4.84 /kWh, 1.2M, 31% coal)
- Entergy Corporation (Louisiana Power & Light, Gulf States, Arkansas Power and Light, etc.) (3.98-5.21 with a system wide average of 4.47 /kWh, 2.4M, 16% coal)
- Houston Industries (Houston Lighting and Power) (4.38 /kWh, 1.4M, 43% coal/lignite)
- Texas Utilities (4.24 /kWh, 5.7M, 26% lignite by capacity but over 40% lignite for actual power generated)

A high level of coal fired power and high industrial prices meant a larger competitive effect from the 1990 CAA. Thus, the Southern Company and Carolina Power and Light (CPL) were the most adversely affected by the passage of this act.

Complying with the CAA: Existing Coal-fired Facilities

Below, we summarize how these utilities complied with the CAA.[40]

Baltimore Gas & Electric met the requirements of Phase I by installing flue gas desulfurization systems, switching fuel, and retiring some units. The necessity for compliance with existing standards and regulations (not just the Clean Air Act) caused BGE to increase capital expenditures by approximately $206 million during the five-year period 1990-1994. If all the expenditure were on coal-fired capacity only, which is unlikely, it would mean capital spending of $81/kW. BGE estimated that the capital expenditures necessary to comply with such standards and regulations would be approximately $16 million, $9 million, and $16 million for 1995, 1996, and 1997, respectively.

The DOE's 1993 Cost and Quality of Fuels Received by Electric Utilities reported on three coal-fired BGE facilities. One very large plant, Brandon Shores, and a small one, Wagner, comprising 78 percent of the total output of the three plants, used low sulfur coal from Kentucky and West Virginia with an average sulfur content of 0.56 lb/MBtu costing about $1.55/MBtu and putting them in compliance with Phase I of the 1990 Clean Air Act Amendments and earning allowances. The remaining small plant, Crane, burnt higher sulfur coal from mines in these two states with sulfur content averaging 1.47 lb/MBtu at a price of $1.51/MBtu.

BGE planned to meet Phase II by using some combination of fuel switching, flue gas desulfurization, unit retirements, and/or allowance trading. The sulfur content of the utility's large Brandon Shores facility at 0.53 lb/MBtu would meet Phase II requirements but the small Wagner plant burning 0.66 lb/MBtu sulfur coal would be just barely out of compliance, a situation it could easily remedy by contracting for a slightly lower sulfur content coal or purchasing a small number of allowances each year.

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[40] The summary below relied on the 1994 10K reports of these publicly owned utilities and on U.S. Department of Energy, Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants 1993,* DOE/EIA-0191(93), July 1994.

BGE estimated that the NO_x controls at its generating plants would cost approximately $70 million (about $28/kW if all coal-fired plants are involved) sometime between now and 1999.

Dominion Resources (Virginia Power) installed a scrubber on one of its three units, at its Mt. Storm coal-fired facility, at a cost of $147 million (very roughly about $250/kW). Mt. Storm was by far the utility's largest coal-fired generating station. The company was assessing whether to install two more scrubbers at Mt. Storm or to rely on allowance purchases for compliance. Dominion estimated that the three scrubbers, NO_x controls, and continuous monitoring (CEM) equipment would come to $481 million in 1992 dollars (or about $526 million in 1995 dollars).

DOE 1993 coal purchasing data indicated that Virginia Power consumed low sulfur Appalachian coal at all but its Mt. Storm facility which was responsible for about 40 percent of the utilities coal based capacity. The sulfur content of the latter plant's fuel was 1.42 lb/MBtu, while the sulfur content of the coal used elsewhere ranged from 0.75-0.85 lb/MBtu except at one small facility employing 1.18 lb/MBtu coal. Mt. Storm was, therefore, out of compliance with Phase I, while the remaining plants were out of compliance with Phase II. Mt. Storm's higher sulfur coal was about $0.17/MBtu cheaper than the low sulfur Appalachian consumed elsewhere.

Carolina Power & Light reported that no further action was necessary in order to comply with Phase I. Phase II compliance would be achieved by burning low sulfur coal and eventually installing scrubbers but delaying their installation until 2007 by purchasing allowances. Some allowances already had been purchased in 1993 and 1994. Phase II compliance costs were estimated at $273 million for the period 1995-1999 and $272 million for 2000-2007. These total expenditures, if spread out over Carolina's entire coal-fired capacity of 6,331 MW, came to $86/kW. Since scrubber installation was not scheduled until 2007, most of the expenditures were probably for NO_x controls. The company asserted that its plans for compliance were not "finalized" and that they were still under review and consideration.

The DOE 1993 data for Carolina Power & Light's coal purchases revealed that of the utility's eight coal-fired plants included in the survey, two were very small, three small, and one was very large, with about half its total generating capacity. All the plants consumed coal from Kentucky, West Virginia, and to a lesser extent Virginia. With one exception, the second largest plant, Mayo, the sulfur content of the coal was about 0.80 lb/MBtu putting them in compliance with Phase I but out of compliance with Phase II. (0.80 lb/MBtu sulfur becomes 1.6 lb/MBtu of SO_2 in the flue gas while Phase II requires no more than 1.2 lb/MBtu.) The Mayo facility was burning low sulfur coal in compliance with Phase II. If 1993 coal purchases approximated the quantity, quality, and sulfur content of the coal to be burned during the Phase II non-compliance years, the utility would have to spend about $5.2 million on allowances per year from 2000 until 2007, based on an allowance price of $130/ton. However, this price could rise near the year 2000 if enough utilities adopted Carolina's approach to compliance.

Duke Power met all its requirements under Phase I by burning low sulfur Appalachian coal. Environmentally related capital costs (not exclusively CAA related) for 1995-1999 were only

$50 million or less than $7/kW of coal based capacity. These costs did not include plans for compliance with Phase II. Plans for the latter were being developed with a wide range of estimated capital costs of $260 to $750 million. Even the high end estimate, however, was relatively modest, coming to only $98/kW of coal-fired capacity, with $260M equating to $34/kW.

The DOE data for 1993 showed that Duke purchased coal from Kentucky, Virginia, and W. Virginia with a sulfur content ranging from 0.69 to 0.91 lb/MBtu and averaging in the neighborhood of 0.8 lb/MBtu. Delivered coal prices varied from plant to plant, ranging from $1.54 to $1.80/MBtu. Duke's coal-fired capacity was dominated by two very large facilities which paid $1.65 and $1.71/MBtu. Price differences were not directly correlated with the variations in the sulfur content of the coal, although coal with twice the sulfur content was quite a bit cheaper. Similar to the case for Carolina Power & Light, the sulfur content of Duke's coal was in compliance with Phase I but not with Phase II. Allowance purchases totaling approximately $6.8 million per year would keep Duke in compliance with Phase II, provided allowance prices remained at $130/ton.[41] However, the company wanted to take a diversified approach to compliance: employing a mix of allowance trading, using low sulfur coal, and installing scrubbers.

In order to earn bonus allowances from 1995-1999, Duke agreed, under 404E of Title IV of the CAA, to switch from 0.8-0.9 lb/MBtu sulfur coal to 0.7 lb/MBtu. The company's supply of low sulfur Appalachian coal was fairly secure because of the long term relationship established between Duke and its coal suppliers. A decision was being weighed on whether or not to install scrubbers at a capital cost of $350 million ($156/kW) at Duke's 2,240 MW Belews Creek Station. The utility was unwilling to rely too heavily on allowance purchases to make up any Phase II non-compliance because, in its 20-30 year horizon, allowances were too uncertain.

Southern Company was a large utility holding company that included Georgia Power, Alabama Power, Gulf Power, Mississippi Power (not to be confused with Mississippi Power & Light), and Savannah Electric Power. Its generating capacity was heavily weighted towards coal and it was the most heavily CAA impacted utility in our group. Eight plants, 35 percent of Southern's capacity, were affected by Phase I. Compliance requirements were met by switching to low sulfur coal and installing low NO_x burners. This approach earned the company surplus emission allowances that it could employ towards achieving Phase II compliance. All of Southern's coal-fired plants were affected by the CAA Phase II requirements and the company was assessing the optimal mix of the three options -- fuel switching, installing FGD equipment, and purchasing allowances. Additional NO_x controls would also be needed.

[41] This estimate could be off by as much as 25% since it is based on DOE figures for coal purchases in 1993 and in addition may not include all of Duke's coal burning plants. Nevertheless it is a good order of magnitude estimate. The present value of the purchase cost of these allowances for 30 years with a discount rate of 12% and an assumed 4% annual increase in the price of these allowances starting at $130 is only $79 million -- much less than the low end of Duke's compliance capital cost of $260 million. For a present value of $260 million under the same discount rate and inflation rate assumptions, the allowance price in the year 2000 would have to reach $429. The difficulty is that this approach would leave Duke without flexibility, especially pertaining to adding new coal-fired capacity. Low sulfur Appalachian coal prices may rise significantly as well.

DOE coal purchasing data showed that by 1993 most of Georgia Power's plants were in compliance with Phase I by virtue of burning low sulfur coal from Appalachia but were not in compliance with Phase II. Georgia Power was sampling Powder River Basin coal at its large Schemer facility. This coal was delivered at the spot price of $1.45 / MBtu.[42]

Entergy Corporation had no need to install additional SO_2 control equipment to comply with Phase II. Phase I was no problem for the company as it had been issued more allowances than it needed and it expected to have excess allowances for sale to others under Phase II. The company's compliance requirements necessitated spending of $5.7 million on NO_x controls and $14.7 million on continuous emissions monitoring equipment (CEM). Future capital investments were estimated to be $16 million in NO_x controls -- a relatively minor sum, and $3 million for additional CEM equipment.

DOE data on Entergy's coal purchases in 1993 revealed that its subsidiary, Arkansas Power & Light, used 100 percent low sulfur coal from Powder River Basin (0.24 and 0.48 lb / MBtu priced at $1.68 and $1.80 / MBtu respectively). Its Louisiana subsidiary, Gulf States Utilities' coal-fired facility did so as well (0.52 lb / MBtu priced at $1.71 / MBtu). The state of Louisiana as a whole consumed a mixture of 20 percent (by heat content) low Btu Louisiana coal with 1.12 lb / MBtu sulfur and priced at $1.39 / MBtu and 80 percent Wyoming coal with 0.52 lb / MBtu of sulfur and priced at $1.63 / MBtu for an average sulfur content of 0.66 lb / MBtu. It should be noted that most if not all of these coal purchases were by contract and the delivered spot price was lower. This use of coal put Louisiana's utilities just outside of Phase II compliance but it could be remedied by increasing the percentage of Wyoming coal consumed by the year 2000. It is clear from this example that Powder River Basin low sulfur coal had extended its reach as far South and East as Arkansas and Louisiana. This low cost coal mining center and the railroads that serve it are looking even further East as can be attested by the fact that Georgia Power is sampling its product.

Florida Power & Light had very little coal-fired generating capacity. Its expected capital expenditures for the 1995-1999 period were from $5 to $16 million per year. The company did not comment explicitly on its CAA requirements. There were no DOE coal purchase data. Phase I & II compliance requirements for coal-fired facilities were not a material issue for this very large Florida utility.

Florida Progress Corporation (Florida Power) also stated that it was not "materially affected by either Phase I or Phase II." To meet Phase II limitations, it was implementing a strategy based primarily on burning cleaner fuels. Continuous emission monitors were installed on most of Florida Power's units by the end of 1994 at a total cost of approximately $11 million. Compliance with nitrogen oxide limitations would require the installation of low nitrogen oxide burners on some coal fired units. These costs would be approximately $8 million

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42 Gulf Power was not in compliance with Phase I in 1993. Alabama Power was in compliance with Phase I with the exception of one very small plant, burning primarily Alabama coal. One large facility in 1993 consumed high quality very low sulfur Alabama coal (0.48 lb / MBtu at $2.52 / MBtu) putting it in compliance with Phase II. Savannah Electric was very small and not of much concern. Finally Mississippi Power Co. had one facility, Daniel Station, that consumed in 1993 a mixture of Kentucky, Colorado, and Montana coal with an average sulfur content of 0.48 lb / MBtu, putting it in compliance with Phases I & II. The second one, the Watson plant, used primarily Illinois coal supplemented by Kentucky coal with a small amount of W. Virginia and Alabama coal that averaged 1.86 lb / MBtu sulfur.

between 1995 and 2000. Florida Power's construction program included approximately $14 million of planned environmental expenditures for air quality projects for the two-year period ending December 31, 1996.

DOE data for 1993 indicated that the utility was burning low sulfur Appalachian coal, primarily from Kentucky and with a sulfur content averaging 0.64 lb / MBtu. Thus, Florida Power was almost in compliance with Phase II. The difference could be made up easily with small purchases of allowances, switching to slightly lower sulfur coal, installing a scrubber at one of its facilities, or some combinations of these options. The company was paying about an average of $1.80 / MBtu for the coal.

Houston Lighting and Power Company built all its coal fired generating capacity after New Source Performance Standards (NSPS) were in force and consequently had no SO_2 emission compliance requirements under Phase I or II aside from expenditures for CEM equipment of $4 million in 1994 and a projection of $7 million for 1995. Houston estimated that the 1977 low NO_x emission standards would cost the company up to an additional sum of $40 million.

The DOE coal purchasing data for 1993 showed that Houston Lighting & Power had two very large coal burning facilities, Limestone and Parish Stations. The larger plant, Parish, responsible for about 60 percent of the power generated by Houston's coal-fired facilities, burned Powder River Basin coal with a sulfur content of 0.45 lb / MBtu and at a relatively high <u>contract</u> price of $2.08 / MBtu. Houston Lighting, therefore, decided to satisfy its NSPS requirements at Parish by burning low sulfur western coal despite its relatively high cost. The Limestone plant consumed Texas lignite with a 1.77 lb / MBtu sulfur content but priced at only $1.27 / MBtu. The latter facility installed scrubbers in order to meet its New Source Performance Standards.

The Texas Utilities Company asserted in its 1994 10K that Phase I had no impact on the company and that 52 of Texas Utilities' 56 generating units were already in compliance with Phase II. The utility further asserted that compliance with Phase II would not have a significant impact on the company but if it did it would simply pass the costs on to its customers. The company did warn that certain of its lignite burning facilities might have to operate at reduced loads from time to time in order to maintain compliance. Texas Utilities had spent $38 million from 1992-1994 on CEM equipment at its lignite generating plants. However of these 56 generating units referred to above only 9 were coal fired systems, the remainder being either nuclear or natural gas fueled.[43] Five of these nine coal based units were constructed after NSPS was in place. All had wet limestone flue gas desulfurization systems installed capable of scrubbing 60 to 80% of the flue gas' SO_2 to meet the NSPS emission limit of 1.2 lb / MBtu. These scrubbers were early models and proved difficult to bring up to full performance capabilities. The remaining 4 coal fired generating units were all built before NSPS and are the only facilities to come under phases I & II of the 1990 CAA Amendments. Since coal based generation was relatively new to Texas, a state that relied heavily on natural gas as a plentiful, locally produced fossil fuel, these 4 pre-NSPS units are the only coal-fired systems in the state impacted by phase I and phase II.

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43 Private communication, Texas Utilities. Our discussion of Texas Utilities and other utilities in the state benefitted from an interview of a staff member in the generating division of Texas Utilities.

DOE data showed the utility with four large to very large lignite-fired facilities. The fuel was of low quality with a high ash content and heating values that varied from 5848 to 6649 BTUs per pound (Powder River Basin coal has about 8500 BTUs per pound and Appalachian coal, while varying, tends to be around 12,000 BTUs per pound.). Out of a total coal fired name-plate capacity of 5875 MW, the 5 units with scrubbers comprised 61% of the total. Four of the five consumed lignite with sulfur content of about 1.7 lb / MBtu and an average 1993 price of approximately $1 / MBtu, the fifth plant burned somewhat lower sulfur lignite priced near $1.30 / MBtu.

The four older Texas Utilities' units that had to meet Phase I and Phase II requirements were in compliance with Phase I by burning low sulfur lignite: the two 575 MW units at *Big Brown* consumed, in 1993, lignite averaging 1.19 lb / MBtu of sulfur and contracted at a price of $1.06 / MBtu and the two 575 MW units at *Monticello* burned lignite averaging 0.87 lb / MBtu of sulfur and contracted at a price of $1.27 / MBtu. The utility had yet to make the decision to either switch to lower sulfur Phase II compliant western coal or install scrubbers. The company earned no allowances under Phase I but would be eligible for them under Phase II. In contrast to the situation for generators replacing higher heat content Appalachian coal with low sulfur but low heat content western coal, Texas Utilities needed no boiler modifications to substitute western coal for its lignite since the former's heat content tended to be about 25% higher and its ash easier to handle. It should be noted that the company had contracts for purchasing its Phase I lignite at very attractive prices. If Texas Utilities chose Phase II compliant western coal instead of installing scrubbers, the Wyoming coal had to come down to an acceptable delivered price, probably in the neighborhood of $1.50 / MBtu or less. Furthermore, since the utility was burning low sulfur lignite, its cost of capturing a ton of SO_2 was high although the cost per kWh was not. This made allowances priced at $130 to $200 / ton of SO_2 a very attractive alternative. Texas Utilities had deferred construction of any new coal fired base load capacity for at least ten years as a new nuclear facility was projected to satisfy any growth in demand.

Utilities in Texas purchased by far the largest amount of Powder River Basin coal of all the states receiving shipments in 1993. This would include many electric energy generators not considered above such as Southwestern Public Service, Southwestern Electric Power, the City of San Antonio, and others. The sulfur content of this western coal was in all cases below 0.40 lb / MBtu corresponding to 0.8 lb SO_2 / MBtu and well below the 1970 Amendments to the CAA New Source Performance Standard (and the phase II compliance level) of 1.2 lb SO_2 / MBtu. All of these generating units in Texas came under this NSPS. It is highly unlikely that any facility coming under the more stringent NSPS of the 1977 CAA Amendments[44] had switched to the higher priced Powder River Basin or other western coal. The average 1993 price paid for Texas lignite by all Texas utilities was $1.17 / MBtu while the average price for all Powder River Basin coal delivered to Texas in 1993 was $1.67 / MBtu. The variation in price of the Wyoming coal was considerable with contract prices as high as $2.10 / MBtu at a Southwestern Public Service plant and as low as $1.18 / MBtu at San Antonio. Some facilities

44 Units for which construction began after September 18, 1978 were required to install scrubbers removing up to 90% of its flue gas SO_2 if burning high sulfur coal and 70% if consuming low sulfur coal. The 1970 CAA NSPS applied to units whose construction began after August 17, 1971 and required that they reduce sulfur dioxide emissions to no more than 1.2 lb / MBtu of fuel consumed.

also purchased Wyoming coal on the spot market at considerably lower prices, for example, the SW Public Service plant that paid the highest contract price bought 11% of its supplies from Powder River on the spot market at $1.08/MBtu. It is clear that the high priced contracts would be rolled over at considerably lower prices.

All Texas electric power generators purchased 90.71 million tons of coal in 1993: 40.8% from Wyoming, 2.0% from Colorado (similarly low in sulfur but with a higher heat content than Wyoming coal), and 57.1% from Texas (low quality lignite with an average sulfur content of 1.7 lb/MBtu). Texas lignite had a considerably lower heat content than the Powder River Basin coal, the reverse of the usual situation when the Wyoming coal replaced Appalachian coal. This eliminated the need, when substituting Powder River coal for Texas lignite, for costly modifications of the boilers and of a derating of the facility.

Complying with the CAA with new facilities--New Source Performance Standards

New electric energy generating systems also faced stricter SO_2 emission standards which would force them to install scrubbers on new coal-fired units. For instance, NSP's last large base load coal-fired unit in 1986 was designed to consume western low sulfur coal in compliance with Phase II, but it had to install scrubbers and other air pollution control devices. The total capital cost incurred was $275/kW which added to the facility's cost by about 1/3.[45] These high additional costs were having a dampening effect on utilities' decisions to install new coal based capacity.

The ten utilities in our sample had planned a total of 7 coal-fired units in 1990 but only 3 of these remained in 1993 plans. In contrast, 9 gas units were planned in 1990 but 21 were planned by 1993. Since then, Duke was completing its huge Lincoln Gas Turbine Station designed to provide peaking power up to 1,184 MW. This $500 million facility ($422/kW)[46] was not included in the 21 units planned in 1993. Carolina Power & Light was planning the addition of one gas unit according to the 1993 DOE report, but announced in 1994 that it was planning 225 MW of GTs at $320/kW in 1997, 1,200 MW of GTs at about $250/kW for 1998-2000, and 1,400 MW of GTs between 2000 and 2007. It also announced that it would build 500 MW of coal-fired capacity for 2008.[47]

Florida Power and Light, had met its capacity needs beyond 2000 by acquiring an existing 646 MW coal based unit from Southern Company and two 430 MW combined cycle gas turbine units. This addition was base load gas-fired capacity where the high efficiency of the CCGT compensated for the higher fuel cost. FP&L already relied a great deal on oil and gas for its fossil fuel based generating systems -- largely for environmental reasons but also because of its long distance from coal supplies.

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45 Based on interviews with NSP staff

46 Interview of Duke Power staff individual.

47 It was unlikely that Carolina Power could actually carry out all these new construction plans, as the utility had relatively high prices and was losing some wholesale power contract sales in 1996 with potentially more to follow. Carolina was under severe pressure to reduce its costs. As part of that process, it had negotiated contracts to purchase 250 MW per year from American Electric Power to 2010 and 400 MW per year until 2000 from Duke Power.

EFFECT OF ENVIRONMENTAL REGULATIONS ON INDUSTRY

In the last section we saw that switching to low sulfur coal, albeit in most cases eastern low sulfur coal, was still the primary approach taken by the group of utilities analyzed to reach compliance under the 1990 Amendments to the Clean Air Act (see Appendix A). They were slow to install scrubbers. Those that did made them a part of a three pronged solution: low sulfur coal, allowances, and scrubbers. Fuel switching usually was the low cost option, allowances could make an important contribution but uncertainties about them were restricting their wider use, and scrubbers were still too expensive but were being employed judiciously by utilities as part of a mix of all three approaches.

A number of these utilities were also beginning to use low sulfur western coal. The efforts of Burlington Northern and Union Pacific to expand markets for Powder River Basin coal bore watching. As of 1993, the contract price for this coal along Southern rail routes, i.e. Texas, Louisiana, and Arkansas remained high but spot prices indicated that contract prices would be falling. Further East, Georgia Power's Scherer plant was sampling Powder River Basin coal (26.3% of the facility's 1993 coal purchases) at an attractive price on the spot market of $1.45/MBtu, well below the utility's average coal purchase cost of $1.78/MBtu for that year.

Finally, it was clear that gas turbines had captured the new peaking capacity market. Prices from $250-422/kW made them ideal for this purpose. The new Duke Power Lincoln Gas Turbine Station would employ a staff of only 12 people for almost 1,200 MW of peak demand capacity.[48] However, the above sample of 10 publicly owned electric utilities did not turn up many examples of large CCGT systems being installed or planned.

Cost issues for these utilities were complex even aside from the regulated aspects of their cost accounting. Each case was highly peculiar to the operating characteristics of the system: what was the demand profile like, what was peak demand like and for how long did it last, what kind of coal was being used and what were its characteristics (sulfur and ash content, etc.), how were boilers designed, what were the labor costs, were there space limitations for installing scrubbers, and so on?

For example, with the exception of units burning Texas lignite, it was much easier for a coal-fired boiler to switch to Appalachian low sulfur coal than it was to switch to Powder River Basin coal. The reason was that the heat content of the Appalachian coal was the same as the heat content of the higher sulfur Appalachian coal it was replacing. Ash characteristics also were the same. Western low sulfur coal had a significantly lower heat content necessitating modifications in the boiler, the coal feeding system, and the ash treatment system. More western coal had to be introduced to generate the same amount of heat. Adjustments had to be made.[49] Switching to Powder River Basin coal for an existing boiler was not cost free and not all boilers would be able to switch at reasonable cost.

48 Private communication

49 In some instances a high heat content fuel had to be mixed in with the low sulfur coal. In many instances the generating system experienced a reduction in maximum output. On average, this reduction or "derating" as it was called could be as high as 10 percent during periods of peak demand. Scrubbers also reduce net busbar output through parasitic power losses. However, this is only about 1.5% of a unit's energy output.

Ripple Effect Leading to Improved Environmental Performance

The sulfur dioxide (SO_2) provisions of the 1990 Clean Air Act (CAA) Amendments Phase I and II threatened to impose substantial costs on coal fired electric power generating plants using high or even intermediate sulfur coal. Original projections of cost were from $400 to as much as $1000 per ton of SO_2 removed. Though not a very useful way to quantify acid rain clean-up costs, this range of estimates could have put the cost of SO_2 removal to a level of 1 /kWh or higher. To place this in perspective: electric utility coal fuel costs had been about 1 /kWh.

In response to these estimates and to the protests of the coal industry, the federal government, in partnership with private industry, spent 7 billion dollars on clean coal technology R&D, about $2.5 billion coming from the government and the rest from utilities and other electricity generators, and from clean coal technology companies. Though SO_2 scrubbing, particulate capture, and NO_x reductions have turned out to cost much less than projected, these investments have had little immediate impact. The government was looking at end-of-pipe (EOP) solutions but the market brought a pollution prevention remedy (fuel switching) instead at dramatically lower cost. Utilities simply reduced the amount of pollutant sulfur at the source. Out of the 65,000 MW of the 1990 CAA Amendments' Phase I impacted facilities, only about 14,000 MW involved the installation of limestone WFGD systems to comply. The remainder, or 78 percent, switched instead to low sulfur coal.

Competition and productivity improvements at Western low sulfur coal (LSC) mines as well as competition and tremendous productivity improvements by the railroads delivering the coal drove the price of LSC down sharply and moved its availability steadily eastward.

At the same time natural gas (NG) prices fell and the availability of this fuel increased, thanks in large part to advances in the technologies for finding and extracting natural gas and oil. As a consequence, the long term prospects for using NG to generate electricity improved markedly. On the generating side a low cost, highly thermally efficient technology for using natural gas was developed as a spin-off of jet engine technology. The fear that high clean-up costs would be imposed on newly constructed coal fired systems and the growing local opposition to siting coal plants were important contributing factors to the increased demand for GT and CCGT systems. The independent power producers (IPP) became a major force driving demand, and the power systems suppliers responded, led by GE, and engaged in a fierce competition that has increased the thermal efficiencies and reduced the prices of these systems.

Gas turbine generating technology blossomed with 60 percent thermal efficiency CCGT systems appearing on the market. This innovation, bred not by environmental regulation alone, was aided by the CAA, especially by the new source performance provisions of the Act. This technology was enabling utilities, either by their own initiation or by IPPs, to meet new capacity needs, especially peak power demand but base load as well, at very low capital and operating costs.

National Comparisons

The competition in the U.S. was between low sulfur coal and natural gas. SO_2 scrubbers, when not mandated, were not a viable option unless they lowered their costs substantially. Globally, however, scrubbers competed with natural gas because low sulfur coal was not as readily available as it was in the U.S. The growth prospects for low sulfur coal and for gas turbine generating systems were high because strong competitive forces stimulated R&D and cost cutting which improved efficiencies and brought down prices. The Clean Air Act (CAA) added to these pressures. It had been expected that the 1990 Amendments to the CAA would also stimulate innovations in scrubber technology. However, it was markets outside the U.S. that were driving technology improvements and lowering costs in this industry. Global market opportunities and not opportunities in the U.S. had the potential to make scrubbers more competitive in U.S. markets.

In Western and Central Europe, acid rain problems were greater than in the United States. Basic industry -- centered in a triangle comprising parts of Poland, the Czech Republic, and Slovakia -- used very low quality, high sulfur coal or lignite resulting in acid rain damage to forests throughout the area and beyond. German forests also suffered significant damage. Low sulfur coal was not readily available as an alternative solution to retrofitting existing plants with FGD devices. Consequently, the market for WFGD was strong and projects were underway or being planned in Poland, Germany, Italy, and elsewhere. Two new lignite burning power plants at Konin, for example, were going to install a large limestone WFGD system to remove 95 percent of the flue gas sulfur.[50]

Effects on Suppliers

The development of the Powder River Basin by the mining companies, of the rail delivery system by BN and C&NW (now UP), and of new low sulfur coal burning technology by the utilities constituted a first class innovative system developed to a large extent in response to environmental regulations on SO_2 emissions. This system provided a low cost pollution prevention solution to many utility CAA compliance problems and promised to provide solutions for more utilities as the rails expanded their markets Eastward. The cost of compliance turned out to be far less than predicted as a result.

Though some power plants were located at the mine mouth, most bituminous coal had to be transported from the mine mouth to the electric generating plant. The overwhelming majority of this coal had been carried by eastern railroads, though barge transport played a minor role. There were two dominant rail carriers in the East: CSX and Norfolk Southern. Conrail and Illinois Central were lesser players. In 1994, coal deliveries were responsible for 32 percent of CSX's and Norfolk Southern's total revenues. CSX and Norfolk Southern, however, were not as aggressive as the western carriers in cutting costs and their rates were higher than those of the western rails.

Key to the success of western coal were the Burlington Northern and Union Pacific Railroads. Chicago & Northwestern, which operated at Powder River Basin jointly with Union Pacific,

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50 The McIlvaine Company, Northbrook IL, *FGD and DeNOx Newsletter,* May 1995, No. 205 .

also was an important player. In 1995 Union Pacific acquired Chicago & Northwestern. The company also announced an offer to purchase Southern Pacific. Southern Pacific had a rail line to the South that could increase the transportation of low sulfur coal to the East. Burlington Northern, meanwhile, was awaiting ICC approval to purchase the Santa Fe Railroad. These acquisitions would leave two large and dominant carriers to serve the western half of the U.S.

The growth in demand for low sulfur sub-bituminous coal had attracted capital, especially to the western railroad companies' coal train operations. Increased competition between Union Pacific and Burlington Northern, and among the many different western coal mine operators, combined with steady productivity improvements to result in a steadily declining price for low sulfur coal and an increased penetration of the product into new markets to the East. Federal courts overturned state laws in Indiana and Illinois that raised barriers to their utilities switching from locally mined high sulfur coal to western low sulfur coal. Test shipments of western coal were delivered to utilities in Georgia and Florida at prices that were competitive with the prices for eastern and mid-western coal currently in use.

The 1970 Amendments to the CAA gave the initial impetus to the exploitation of the Powder River Basin coal reserves. The Federal Government, through the Interstate Commerce Commission, played an important role in encouraging the Chicago & Northwestern and the Burlington Northern to develop jointly and share the track that had to be built from the mines to their main rail lines rather than build two separate but parallel lines to serve each of the rail companies. This approach contributed to the reduction in transportation costs. The ICC was persistent in encouraging the financially weak C&NW to enter the market to provide competition. When it did, after considerable delays, transportation prices plummeted.[51]

In 1994, coal transport generated 33 percent of Burlington Northern's rail revenues and 19 percent of Union Pacific's. Burlington's and Union Pacific's systems reached as far East as Chicago to the North and St. Louis and Memphis on the Mississippi to the South and a bit beyond to the Tennessee River. The coal then could be carried further South by barge or further East and South by passing the cargo off to the CSX and Norfolk Southern railroads. Rail was by far the cheapest overland mode for carrying coal. There were no barge carrying waterways available to Powder River Basin mines. Burlington Northern and Union Pacific, while in fierce competition with one another, had complete control of this market.

SUMMARY

Two lessons were clear: competition was a creative force that had helped to improve the environment at lower cost; and the way in which the competitive forces had unfolded would have been hard for the government to predict.

For instance, competition in the rail industry and the working out of costly work rules helped lead to the dramatic cost reductions in the delivery of low sulfur coal and the opening up of markets further East than had been previously imagined. By leasing low sulfur coal reserves

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[51] If the railroads were simply deregulated and the ICC played no role, then it was likely that the Union Pacific would have entered the market anyway and perhaps sooner and more effectively.

on Western Federal lands to a number of companies, the government ensured a fully competitive market that had helped to achieve low mine-mouth coal prices.

The Federal Government had also played a role in the productivity improvements in natural gas by deregulating and encouraging competition. The wellhead price and cost of delivery of natural gas fell after the federal government deregulated prices. Technology developments in finding gas and oil were encouraged. They made the long term outlook for sufficient supplies of NG at reasonable prices more favorable.

These technology innovations came at a critical time in the evolution of the utility industry. Increased competition, deregulation, and the consequent need to reduce costs required the industry to find solutions to CAA regulations at much lower costs than originally envisioned when the legislation was forged. In turn, the increased competition in the electric utility industry fed back on the competing solutions providers: the low sulfur coal providers, the gas turbine makers, and the scrubber manufacturers. These suppliers had to continue to innovate to drive costs down further.

SO_2 trading allowances were another innovation that was helping to lower costs, though deficiencies in this market (too thin) and uncertainties as to future prices and even to the future existence of the market were hindering further innovation.

APPENDIX A

The Phase I & II Compliance Strategies of the Utilities

1. All (with the exception of Florida Power & Light, which had almost no coal based generating capacity) resorted to using low sulfur coal as the core of their compliance strategy. Along the Southeast and closest to Appalachian coal mines, the source of the coal was Appalachian that was in most cases Phase I compliant only. Southern Company, however, with plants running from Georgia to Alabama, Louisiana, and Mississippi was using some western coal that was Phase II compliant. Of great significance was the fact that Georgia Power was testing some Powder River Basin coal delivered at a competitive price.
2. Powder River Basin coal had penetrated to the South Central United States. It provided Entergy Corporation the complete solution to its SO_2 compliance problems and helped Houston P&L meet New Source Performance Standards.
3. While many of the units in this sample burned non-compliance coal, none of the coal had high sulfur content, the highest tending to be about 1.8 lb / MBtu. Consequently, none of the utilities were contemplating the use of scrubbers as the sole supplement to using low sulfur Appalachian coal in order to meet Phase II compliance requirements by 2000.
4. The purchase of allowances as part of the solution to Phase II needs was being considered by all the out of compliance companies. Because low sulfur Appalachian coal was not very far out of compliance for Phase II, the purchase of allowances appeared to be the cheapest way for units burning this coal to satisfy Phase II SO_2 emission limits. Carolina Power & Light was adopting this approach but only from 2000 to 2007. The uncertainty about the long term stability or even existence of allowance trading was strongly inhibiting the utilities from relying solely or heavily on them for their compliance needs.
5. As a consequence, those utilities using low sulfur Appalachian coal, several with some units consuming intermediate sulfur coal, were in the process of analyzing their three options: lower the sulfur content of their coal even further, install scrubbers, or purchase allowances. In developing a solution, the utilities had to consider not only the lowest cost option but the risks and volatility of the solution.

- What would happen to the price of allowances as the year 2000 approached and Phase II demand drove up the price?

- Would the allowance program survive for 30 years, the time horizon for the analysis?

- Would the regulations survive 30 years?

- What if they were made less stringent? What would the Republican controlled Congress do?

- What would the supply and demand characteristics of low sulfur Appalachian coal be as everyone sought to switch to it?

- Was there a 30 years supply of this coal at an acceptable price?

- If a scrubber was installed, would it be accepted as part of the rate base?

- With growing competition, would industrial customers be willing to pay for its cost?

- What if a much better, lower cost scrubber came along in a few years? Perhaps delaying the installation of a scrubber made sense?

- The fact that none of the utilities pondering these issues had reported a final decision indicated that the answers to these and other vexing questions were not easily and that, perhaps, there was no clear or optimal solution.

6. The Baltimore, Virginia, Carolina utilities had not considered Powder River Basin coal as a viable alternative strategy, yet Burlington Northern, was ready to bring western coal East and beyond. If Georgia Power made more aggressive use of Powder River Basin coal would this change the perspective of the other companies in the region.

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