COMPETITIVE IMPLICATIONS OF ENVIRONMENTAL REGULATION:
A CASE STUDY ON
Carolina Power and Light (CPL)

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INTRODUCTION

Carolina Power and Light (CPL), a large utility in the Southeastern part of the United States, had to decide how it should respond to the 1990 Clean Air Act (CAA). What impact would this legislation have on its existing power plants, which used coal for a fuel? What effects would the CAA have on CPL's plans to build new generating capacity?

ENVIRONMENTAL PRESSURES FACING THE INDUSTRY

The 1970 Clean Air Act authorized the EPA to set ambient SO_2 standards protect health and prevent damage to materials. It only applied to concentrations at ground level and did not prevent sources from building high stacks which transported emissions to other areas and states.

In 1990, after a decade of debate, Congress and the administration 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 which formed nitrogen oxides (NO_x), as a consequence of the combustion process. According to the EPA's 1989 emissions inventory, utilities were responsible for 69.4 percent of U.S. SO_2 emissions and 32.4 percent of total NO_x emissions.

Phase I

Implementation of sulfur dioxide emission reductions was to be achieved in two phases. 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. The CAA required power plants to cut sulfur dioxide emissions to 2.5 lb/MBtu or less by January 1, 1995 . Two-year extensions could be given to plants that committed to buy scrubbing devices. This form of secondary treatment allowed continued use of high-sulfur coal. Local ambient air standards could necessitate the use of scrubbers due to lower SO_2 emission requirements.

<u>Nitrogen Oxide Reductions</u>

Beginning in 1995, utilities would have to cut nitrogen oxide emissions as well. Except for areas heavily impacted by smog, or other local situations that prompted stricter controls, NO_x restrictions were expected to be met by installing low NO_x burners at a relatively low cost.

<u>Pollution Trading System</u>

The 1990 Clean Air Act also included an innovative pollution-trading system. Under Phase I, generators were given enough allowances (1 ton of SO_2 per allowance) to emit the maximum allowable level of 2.5 lb/MBtu. The total number of allowances granted to a facility was based on its annual average 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. If the facility emitted levels below the limit of 2.5lb./MBtu, it could retain any remaining allowances.

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 facing costs of SO_2 emission reduction higher than the price of the allowances. Utilities might also choose to keep unused allowances for their own use should they need to expand capacity in the future. Units that cut emissions by reducing output as a result of energy conservation efforts also were 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 emissions before the CAA Amendments took effect.

Phase II

A similar procedure was in place for the lower limits required in Phase II., scheduled to begin January 1, 2000. More than 1900 additional units rated at 25 MW or greater, as well as the plants affected by Phase I, 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 establish a fixed cap on emissions of 8.95 million tons of SO_2 per year. New capacity would not be issued allowances and had to obtain them from existing holders instead.

To put this cap in perspective, total power plant SO_2 emissions in 1993 were 14.4 million tons leaving a required reduction of about 5.4 million tons. 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 Source Performance Standards (NSPS)

New coal burning facilities would be limited even further due to provisions of the 1970 CAA and 1977 CAA Amendments which set "New Source Performance Standards." 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 a sulfur content less than or equal to 0.6 lb/MBtu. 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 CAA Amendments 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 removing 90 percent of emitted SO_2. Removal rates dropped to as low as 70 percent for low-sulfur coal users. Although systems with 70 percent absorption rates were less costly than those with 90 percent absorption rates, this provision dampened the utilities' enthusiasm for low-sulfur (western) coal. These standards served as an impetus toward natural gas turbine generators.

Existing plants that underwent modifications (improvements in boiler efficiency, for example) might have had to face not only re-permitting requirements, but also 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.

The Clean Coal Initiative

The federal government's Department of Energy (DOE) also was involved in a "Clean Coal Technology" (CCT) program to develop better, lower cost pollution control technologies for coal-fired generating plants. About $7 billion had been spent (34 percent from the federal government, 3 percent from state agencies, 51 percent from power generators, with the remainder coming 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 NO_x burner systems and less costly 50-60 percent SO_2 removal systems used when retrofitting older boilers. Several advanced wet flue gas desulfurization (WFGD) systems were part of the program as well. Babcock and Wilcox (B&W), Asea Boveri Brown (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 in SO_2 control projects. GE Environmental Services, Inc. did not participate because successful technologies developed under the CCT program had to be shared with competitors.

CLEAN COAL TECHNOLOGIES

Main Coal Types

<u>Bituminous Coal</u>

Bituminous coal tended to be about 70 percent carbon and a few percent hydrogen which together represented the heating value of the mineral. The remainder 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 used by generating facilities usually contained less than 4 percent.

In 1993, total bituminous coal purchased by utilities contained 1.71 percent sulfur on average. At an average of 12,045 Btu/lb., this concentration corresponded to 1.42 pounds of sulfur per million Btu (MBtu) heat content.

The sulfur content of the coal in Appalachian mines varied, and the amount of low-sulfur coal in reserves 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.

<u>Sub-bituminous Coal</u>

Sub-bituminous coals were of lower quality than bituminous coals: compared to 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 boiler operators found that it yielded troublesome amounts of fine ash in the flue gas which was difficult to control. 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.

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. Low- sulfur sub-bituminous western coal differed sufficiently from higher-sulfur such that it usually could not be substituted for bituminous coal in boilers without modifications.

Low Sulfur Coal from the West

Both 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. Serious development of the mines began with the passage of the CAA in 1970. The 1971 version of new source performance standards created demand for low-sulfur coal. The oil supply crises of the 1970s and skyrocketing energy prices inspired investment in this commodity. The 1980s saw substantial advances by mining companies towards 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 14-234/MBtu. A miner in Wyoming or Montana produced over 20 tons of coal in an hour, in contrast to Appalachia where one hour's labor brought in only 3 tons of coal.

Western coal delivered to utilities in such states as Nebraska, Iowa, Kansas, Minnesota, and Wisconsin was selling for about $1/MBtu (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 to and from the Powder River Basin. During the 1970s, tracks to the many mines had to be laid. Although BN and the Chicago & Northwestern (C&NW) jointly owned the rights of way, it was BN which had the initial capital to lay the tracks.

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. 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 by 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 (GM and GE were in strong competition for these innovations), 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 prior to 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.[1]

The continued growth prospects the railroads saw for hauling western coal continued to spur technological improvements. A new, more powerful locomotive introducing AC electric traction motors promised to lower operating costs. Burlington Northern designers and engineers designed a "Trough Train" composed of extended cars of 13 articulated sections that increased the coal carrying capacity of a unit train by 30-40 percent. The doors were completely redesigned for easier unloading. The new, more aerodynamic exterior provided the added benefit of reduced wind resistance. Lighter car bodies made of aluminum replaced steel to further improve the efficiency of the coal delivery system. 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 even further. As Table 1 below shows, this vision was close to becoming a reality.

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[1] 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 Coal fell substantially.

Table 1

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).*

Scrubbers

The 1990 CAA regulated the following pollutants: sulfur dioxide, nitrogen oxides, particulates from the ash, and several hazardous air pollutants (HAPs).[2] A variety of scrubbers to control SO_2 were on the market:

Limestone Wet Flue Gas Desulfurization Systems (WFGD)

This was 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 as much 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 differing sulfur contents. They could be used to retrofit existing units, and installed in new facilities as well.

Capital costs for a system with 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 started at $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.

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[2] Emission standards for HAPs were under review and it was not clear to what extent utilities would have clean-up responsibilities. 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.

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. (GEES), 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 with high demand for gypsum. Otherwise, the expense did not make this added investment worthwhile. In Western Europe, on the other hand, the capability to convert scrubber sludge into a useful byproduct was often essential. Landfill permits to dump waste sludge were not easily available. In Germany, 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. They fell in the neighborhood of 0.054/kWh, with limestone costing only $10/ton. A good estimate of the additional revenues needed to pay for WFGD systems was 0.44/kWh, which was greater than the added cost of fuel for burning natural gas in a combined cycle turbine generator.

Dry FGD

This system sprayed an agent, usually lime in a slurry, and the agent was then 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 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 principle, 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. Other injection systems had been developed, however, 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.

Ammonia Reagent System

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, yielding a byproduct of granulated ammonium sulfate, which was 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 treatment capability to make the ammonium sulfate. Unlike the sales of the low priced gypsum byproduct, which 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, providing 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 a 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 warranted examination as it was the only new technology that could challenge conventional systems at a lower cost. Worldwide demand for the new, lower cost ammonium sulfate scrubber (when the facility was 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.

Combined Removal Systems

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 Mitsu--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.

General Electric licensed to develop the system by Bergbau Forschung and planned to adapt the system for North American markets. The system had been tested in plants in Germany and Japan and was capable of very high (greater than 98 percent) SO_2 removal rates, 70-90 percent NO_x removal, greater than 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, while 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.

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 a July 1994 report on clean coal technologies, 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 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 also was being tested at an Ohio Edison facility, this one at Niles Station. According to the company, "The utility is making the technology a key part of its 1990 CAA compliance strategy." 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 funding under the Clean Coal Technology program.

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 limit for coal), and much fewer HAPs. Equally important, they had less neighborhood impact than coal-fired units.

Single Gas Turbine (GT) Units

GT Units were a spin-off of the jet aircraft engine, modified for stationary power application and for burning natural gas. They 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 MWs 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 were often employed for cogeneration purposes.

Combined Cycle Gas Turbine Systems (CCGT)

CCGTs 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 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 approximately $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 could also 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 generators who preferred to respond to new capacity demands with one increment at a time to avoid the risk of having too much capacity (which could result when coal-fired plants were built to be 500 MW or greater). A 250 MW CCGT could be installed n two years or less. GT systems with low capital costs often were used to provide peaking power capacity for a few days per year. CCGTs had sufficiently high thermal efficiencies, thus making them suitable for intermediate and base load applications.

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

Technological and Cost Improvements in NG Systems

Natural gas turbine (GT) and combined cycle gas turbine (CCGT) electric power generating systems had experienced dramatic technological and cost improvements. At first, innovations were driven by non-environmental forces, but more recently driven by the desire for environmentally-friendly features as well as related technical and economic benefits. After the passage of the 1990 CAA Amendments, the major manufacturers, led by GE, drove the thermal efficiency of combined cycle gas turbine generators (CCGT) from below 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.

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 advanced drilling technologies. 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.

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 levels coming from coal-fired boilers. HAP emissions were lower and mercury and other heavy metals 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.

CUSTOMERS

The electric utilities were the customers for these competing technologies. They were undergoing dramatic change driven by the pressures that came from their industrial customers who were in search of lower costs and by state and federal regulators who were slowly moving towards increased deregulation and competition. Most utilities charged their captive industrial customers an electricity price that was higher than the marginal cost. Neighboring utilities often had different prices for their electricity, a disparity that could have arisen from a variety of causes.[3]

Large consumers of electric energy saw nearby utilities offering power at lower rates than their own utility 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.

The new competitive forces in the electric utility industry were the result of forces in the global economy. Manufacturers were in a position where cost increases could not be easily passed on to customers. They had

3 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 64/kWh, sees a competitor in the Mid-West paying only 44/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 34/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.

to cut costs to maintain profitability and market share. Inject the 1990 Clean Air Act Amendments and the utility industry, beset by cost conscious customers, 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.

To illustrate how they faced these challenges, the response of the utilities in a region that sweeps in an arc from the Southeast into Texas will be presented. These utilities are 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 the electricity made in the U.S.

Below in parentheses were the average prices in 4/kWh that they charged their industrial customers in 1994; the population served is in millions; and the percentage of capacity provided by their coal-fired facilities is provided as well.

- Baltimore Gas and Electric (4.644/kWh, 2.6M, 44% coal)
- Dominion Resources (Virginia Power) (4.334/kWh, 1.8M, 39% coal)
- Duke Power (4.244/kWh, 4.9M, 43% coal)
- Southern Company (Georgia Power, Alabama Power, Mississippi Power, etc.) (3.70-4.52 with a system wide average of 4.304/kWh, 11M, 73% coal)
- Florida Power and Light (FPL Group) (4.914/kWh, 6.5M, 6% coal)
- Florida Progress Company (FPC) (4.844/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 4.474/kWh, 2.4M, 16% coal)
- Houston Industries (Houston Lighting and Power) (4.384/kWh, 1.4M, 43% coal/lignite)
- Texas Utilities (4.244/kWh, 5.7M, 26% lignite by capacity but over 40% lignite for actual power generated)

Carolina Power and Light charged 5.294/kWh to its industrial customers, served 3.5 million people, and was 60 percent dependent on coal. A high level of coal fired power and high industrial prices meant a larger competitive effect from the 1990 CAA. Thus, CPL and the Southern Company were the most adversely affected by the passage of this act.

Case B

Complying with the CAA: Existing Coal Fired Facilities

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 was on coal-fired capacity only, it meant 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.

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. Yet, 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.

BGE estimated that the NO_x controls at its generating plants would cost approximately $70 million (about $28/kW if all coal-fired plants) sometime between 1995 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).

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 second phase 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, amounting to only $98/kW of coal-fired capacity, with $260M equating to $34/kW.

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 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 also would be needed. Georgia Power was sampling Powder River Basin coal at its large Schemer facility. This coal was delivered at a very attractive price ($1.45/MBtu).[4]

Entergy Corporation did not have to install additional SO_2 control equipment to comply with Phase II. Phase I was no problem for the company because it had been issued more allowances than it needed. Furthermore, it expected to have excess allowances for sale to others under Phase II. The company's compliance requirements required spending of $5.7 million on NO_x controls and $14.7 million on

[4] 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.

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.

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 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 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.

Houston Lighting and Power Company made no mention of SO_2 emissions 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 $40 million.

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 cost $2.08/MBtu -- a relatively high price. The Limestone plant consumed Texas lignite with a 1.77 lb./MBtu sulfur content but priced at only $1.27/MBtu. The latter facility was out of compliance with both Phase I & II.

The Texas Utilities Company asserted 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 significantly impact the company, but in case 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. There was no mention of installing scrubbers.

The utility had 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 varied, tended to be around 12,000 Btus per pound.). In 1993, two of the four plants used low enough sulfur lignite to gain compliance with Phase I and the other two did not. The lignite, coming from Texas, was very cheap. The company, in 1993, paid from $0.98 to $1.27/MBtu for the lignite with sulfur contents of 1.80 lb./MBtu to 0.87 lb./MBtu respectively.

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 for NO_x controls.

The DOE's 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 were small, and one was very large, with about half its total generating capacity. All the plants consumed coal from Kentucky, West Virginia, and Virginia to a lesser extent. 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 required 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.

The company asserted that its plans for compliance were not "finalized" and that they were still under review and consideration.

New Performance Standards

These ten utilities had planned a total of 7 coal-fired units in 1990 but only 3 of these remained in the 1993 plans. In contrast, 9 gas units were planned in 1990 but 21 were planned by 1993. Since then, Duke had completed its huge Lincoln Gas Turbine Station designed to provide peaking power up to 1,184 MW. 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.

Carolina Power & Light was planning the addition of one gas unit according to their 1993 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.

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.